federal register

Tuesday
February 17, 1981

Part IV

Department of Energy

Bonneville Power Administration

Intent to Revise Transmission Policy and Proposed Transmission and Wholesale-Power Rate Adjustments; Public Hearings and Opportunities for Public Review and Comment

DEPARTMENT OF ENERGY

Bonneville Power Administration

Intent To Revise Transmission Policy; Request for Recommendations From the Public

AGENCY: Bonneville Power Administration (Bonneville), Department of Energy.

ACTION: Notice of Intent to Revise Transmission Policy; Request for Recommendations from the public.

SUMMARY: Bonneville Power Administration (Bonneville) intends to revise its transmission policy. The initial stages of the policy revision will coincide with development of Bonneville's transmission rates which will become effective on or about July 1, 1981. In addition to receiving recommendations on its Notice of Proposed Transmission Rate Adjustment, Bonneville is seeking recommendations from the public on transmission policy at its rate hearings in March 1981. Written suggestions and recommendations are also encouraged.

Formulation of the transmission policy will follow Bonneville's "Procedure for Public Participation in Marketing Policy Formulation" (45 FR 73531, November 5, 1980). Recommendations received will be considered initially to develop interim agreements necessary to implement an optional rate schedule to be offered in the transmission rates which will become effective July 1, 1981, and subsequently to develop an initial proposal for a long-range transmission policy. The proposal is expected to be published in the fall of 1981. Based in part on comments and recommendations received in response to the initial proposal, Bonneville expects to announce a final policy in the spring of 1982.

DATES: Written suggestions and recommendations for issues to be addressed or other matters concerning the development of Bonneville's initial proposal for a revised transmission policy will be accepted through March 31, 1981.

ADDRESSES: Written recommendations should be submitted to the Public Involvement Coordinator, Bonneville Power Administration, P.O. Box 12999, Portland, Oregon 97212.

FOR FURTHER INFORMATION CONTACT: Donna L. Geiger, Public Involvement Coordinator, Bonneville Power Administration, P.O. Box 12999, Portland, Oregon 97212; the telephone number is (503) 234–3361, ext. 4261. Bonneville maintains toll-free lines for the use of persons within the region. Oregon callers may use 1–800–452–8429; callers in Washington, Idaho, Montana, Wyoming, Utah, Nevada, and California may use 1–800–547–6048. Messages and requests for information received after normal business hours (after 4:30 p.m. and before 7:30 a.m.) may be recorded on the toll-free lines. Additional information is available from Ronald H. Wilkerson, Spokane Area Manager, Room 561, U.S. Courthouse, West 920 Riverside Avenue, Spokane, Washington 99201, (509) 456–2518; Gordon H. Brandenburger, Kalispell District Manager, P.O. Box 758, Kalispell, Montana 59901, (406) 755–6202; Ronald K. Rodewald, Wenatchee District Manager, Room 314, U.S. Federal Building, 301 Yakima Street, Wenatchee, Washington 98801, (509) 662–4377; John H. Jones, Portland Area Manager, Suite 288, 1500 Plaza Building, 1500 NE. Irving Street, Portland, Oregon 97208, (503) 234–3361, ext. 4551; Ladd Sutton, Eugene District Manager, Room 206, U.S. Federal Building, 211 East 7th Street, Eugene, Oregon 97401, (503) 345–0311; Randall W. Hardy, Seattle Area Manager, 415 First Avenue North, Room 250, Seattle, Washington 98109, (206) 442–4130; Roy Nishi, Walla Walla Area Manager, West 101 Popular, Walla Walla, Washington 99362, (509) 525–5500, ext. 701; Robert N. Laffel, Idaho Falls District Manager, 531 Lomax Street, Idaho Falls, Idaho 83401, (208) 523–2706.

SUPPLEMENTARY INFORMATION: Bonneville owns and operates approximately 80 percent of the capacity of the high-voltage electric transmission grid of the Pacific Northwest. Bonneville is required by the Federal Columbia River Transmission System (FCRTS) Act of 1974 (16 U.S.C. 838) to operate, maintain, and construct the FCRTS to: "(a) integrate and transmit electric power from existing or additional Federal or non-Federal generating units; (b) provide service to the Administrator's customers; (c) provide interregional transmission facilities; or (d) maintain the electrical stability and electrical reliability of the Federal system."

Bonneville's current transmission policy is reflected in a variety of transmission arrangements and agreements which have been progressively negotiated over a period of years. Many of these arrangements predate the 1974 FCRTS Act and reflect conditions and policies prevalent at the time of negotiation. Types of provisions which may vary from agreement to agreement include the determination of the transmission demand, determination of losses, the effect of transmission distance and location, and the flexibility allowed in the use of the FCRTS.

Bonneville now intends to develop a comprehensive and internally consistent transmission policy and resultant rates. The tentative schedule for this policy development is as follows:

February 1981—This Notice and a Notice of Proposed Transmission Rate Adjustment are published. The latter Notice contains a proposed Integration of Resources Schedule (IR-1) which Bonneville intends to offer to customers who elect to receive service under interim 1-year contracts. Bonneville anticipates presently that the service offered under these interim contracts will be a broader and more flexible service than that offered under most existing agreements. Key aspects of this anticipated service include multiple points of integration and delivery, uniform system-average loss determination, and a uniform capacity rate.

March-April 1981—Hearings will be held on the transmission rate proposal. At these hearings Bonneville encourages the public to make transmission policy recommendations and suggestions. The recommendations and suggestions received will be considered both in formulating interim agreements for schedule IR-1 and in developing an initial proposal for a long-term transmission policy.

July 1981—Bonneville's new transmission rates will become effective. Interim agreements will be negotiated with those utilities electing to receive service under schedule IR-1.

Fall 1981—Bonneville will publish a proposed Transmission Policy and Request for Public Comment. Public hearings on the proposed policy will be held during which public comments will be received.

Spring 1982—Bonneville will publish a Notice of Final Transmission Policy.

July 1982—Bonneville will offer long-term contracts under the adopted Final Transmission Policy.

Bonneville is seeking suggestions and recommendations on all aspects of its transmission policy and especially on the following issues which Bonneville has identified: (1) What method should be used to determine the amount of and compensation for transmission losses? (2) To what extent is it appropriate to recognize (a) the use of specific facilities, (b) the use of specific types of facilities, (c) the distance between resources and loads, and (d) the location of resources and loads? (3) How should the costs and uses of non-Federal transmission facilities be treated, more specifically: (a) Should the Pacific Northwest institute a system in which

all parties using the combined regional transmission system would be assessed transmission charges in proportion to the loads placed on the system and credited according to the transmission costs each has incurred? (b) If not, to what extent should the amount of non-Federal use of the FCRTS and Federal use of non-Federal facilities be determined? and (c) How should that determination be made, particularly in areas with multiple transmission paths? (4) What is the appropriate service or services for Bonneville to offer its transmission customers? (5) How can transmission policy encourage one-utility planning? (6) What is the proper treatment of existing contracts whose holders prefer not to receive the revised policy service? (7) How can transmission policy encourage energy conservation? (8) To what extent should the benefits and risks of the FCRTS be shared?

Written recommendations concerning the above issues or other issues that should be considered by Bonneville in developing its transmission policy should be addressed to Bonneville's Public Involvement Coordinator.

Dated: February 10, 1981.

Earl Gjelde,

Acting Administrator.

[FR Doc.81-5371 Filed 2-12-81; 11:00 am]

BILLING CODE 6450-01-M

Proposed Transmission and Rate Adjustment; Public Hearings, and Opportunities for Public Review and Comment

AGENCY: Bonneville Power Administration (Bonneville), Department of Energy.

ACTION: Notice of Proposed Transmission Rate Adjustment, Notice of Public Hearings, and Opportunities for Review and Comment.

SUMMARY: Bonneville has determined that an increase is necessary in the transmission rates charged for the use of the Federal Columbia River Transmission System (FCRTS). Revenues from the current transmission rates, which were approved on an interim basis on June 10, 1977, are insufficient to recover the increased costs of the FCRTS. Bonneville, by a separate **Federal Register** Notice, is also initiating a process to formulate a transmission service policy.

The development of the transmission rates includes opportunities for interested persons to participate in public hearings. Written comments will be received until the end of the hearings and all such written comments will become part of the Official Record. Bonneville will consider the comments and hearing record in the development of the final transmission rate proposal. With consideration of public comments, and/or inclusion of more current financial data, the final rate proposal may differ from the rates proposed in this Notice.

DATES: Persons wishing to become a formal "party" to the proceedings must notify Bonneville in writing of their intention to do so. The notification must be received by February 24, 1981, and should be addressed as follows: Hon. Dean F. Ratzman, Hearing Officer, Bonneville Power Administration. P.O. Box 12999, Portland, Oregon 97212. Power and transmission customers of Bonneville are parties of right. Others may become parties by demonstrating in their notice and at the prehearing conference that they would represent a significant and otherwise unrepresented public interest. The notice should contain: (1) The name of the person or entity claiming status as a party; (2) the person who will be representing the party; (3) whether the person or entity claiming status as a party has a contractual relationship with Bonneville which could be impacted by proposed rates; and (4) if no contractual interest exists, the interest the person believes would be served by their being a party. All timely applications will be ruled upon by the Hearing Officer.

Pursuant to the rate procedures, a Prehearing Conference will be held before the Hearing Officer at 9 a.m. on February 25, 1981, in the West Ballroom, Red Lion Lloyd Center, 1000 NE. Multnomah, Portland, Oregon.

The rates hearings will concern both the transmission rates and the wholesale power rates and will begin with a presentation of the studies and the basis for the proposed wholesale power and transmission rates by the Bonneville staff. Registration for the hearing will begin at 8:30 a.m. and the hearing will commence at 9 a.m. on March 2, 1981, in the Main Ballroom of the Masonic Temple, 1119 SW. Park Avenue, Portland, Oregon. The presentation of the staff case may continue into March 3 and 4, 1981. Clarifying questions will be permitted.

At the conclusion of the staff presentation, six hearings will be held at locations outside Portland, to present to the public and other interested persons a condensed form of the Bonneville staff case and to receive the views, opinions, and comments of the general public. The public's comments will be subject to cross-examination. Presentation of testimony and evidence from formal parties will not be allowed at these sessions. Registration for the hearings will be at 7 p.m., and the hearings will begin at 7:30 p.m. The dates and locations are: March 5, Parrish Middle School Auditorium, 802 Capitol Street NE., Salem, Oregon; March 9, Blackfoot Room, Village Red Lion, 100 Madison, Missoula, Montana; March 10, Training Office Auditorium, Boise Interagency Fire Center, 3905 Vista Avenue, Boise, Idaho; March 11, Federal Building, 3000 George Washington Way, Richland, Washington, and March 12, Snoqualmie Room, Seattle Center, 1st North and Republican Street, Seattle, Washington. Bonneville will hold a sixth hearing on Friday, March 13, from 1 p.m. to 4 p.m., in Room 15018 of the Golden Gate Federal Building, 450 Golden Gate Avenue, San Francisco, California.

Bonneville expects that during the prehearing conference, hearing dates will be set for cross-examination of the Bonneville staff, for the presentation of the cases of formal parties, and for rebuttal and oral argument. A notice of the dates and times of such hearings will be mailed to all parties of record. In addition, the hearings may be continued for the presentation of other information which may affect significantly the Bonneville rate case, and for the taking of rebuttal testimony and cross examination regarding such new information. Written comments may be submitted until the close of the hearings. The last day for receipt of written comments will be specified in a later **Federal Register** Notice.

ADDRESSES: Written comments not submitted at the hearings should be submitted to the Public Involvement Coordinator, Bonnevill Power Administration, P.O. Box 12999, Portland, Oregon 97212. Written comments received by the close of the hearing will be made part of the record.

FOR FURTHER INFORMATION CONTACT: Donna L. Geiger, Public Involvement Coordinator, Bonneville Power Administration, P.O. Box 12999, Portland, Oregon 97212; the telephone number is (503) 234-3361, ext. 4261. Bonneville maintains toll-free lines for the use of persons within the region. Oregon callers may use 1-800-452-8429; callers in Washington, Idaho, Montana, Wyoming, Utah, Nevada, and California may use 1-800-547-6048. Messages and requests for information received after normal business hours (after 4:30 p.m. and before 7:30 a.m.) may be recorded on the toll-free lines. Additional information is also available from: Ronald H. Wilkerson, Spoken Area Manager, Room 561, U.S. Courthouse, West 920 Riverside Avenue, Spokane,

Washington 99201, (509) 456–2518; Gordon H. Brandenburger, Kalispell District Manager, P.O. Box 758, Kalispell, Montana 59901, (406) 755–6202; Ronald K. Rodewald, Wenatchee District Manager, Room 314, U.S. Federal Building, 301 Yakima Street, Wenatchee, Washington 98801, (509) 662–4377; John H. Jones, Portland Area Manager, Suite 288, 1500 Plaza Building, 1500 NE. Irving Street, Portland, Oregon 97208, (503) 234–3361 ext. 4551; Ladd Sutton, Eugene District Manager, Room 206, U.S. Federal Building, 211 East 7th Street, Eugene, Oregon 97401, (503) 345–0311; Randall W. Hardy, Seattle Area Manager, 415 First Avenue North, Room 250, Seattle, Washington 98109, (206) 442–4130; Roy Nishi, Walla Walla Area Manager, West 101 Poplar, Walla Walla, Washington 99362, (509) 525–5500 ext. 701; Robert N. Laffel, Idaho Falls District Manager, 531 Lomax Street, Idaho Falls, Idaho 83401, (208) 523–2706.

SUPPLEMENTARY INFORMATION:

Bonneville Power Administration operates and maintains the Federal Columbia River Transmission System in order to: (a) Integrate and transmit the electric power from existing or additional Federal or non-Federal generating units; (b) provide service to the Bonneville customers; (c) provide interregional transmission facilities; or (d) maintain the electrical stability and electrical reliability of the Federal system. The FCRTS along with Federal generation and non-Federal generation marketed by Bonneville at wholesale to the region's utilities and other entities comprises the Federal Columbia River Power System (FCRPS). A repayment study and other supplemental studies of the FCRPS are used to determine the revenue necessary to recover the costs associated with the production, acquisition, conservation, and transmission of the electric power that Bonneville markets or transmits for customers, and to repay with interest the Federal investment in the transmission and generation facilities of the FCRPS as required by statute. The proposed transmission rates, plus the proposed wholesale power rates, are designed to produce the necessary total revenues. Rates must be set such that recovery of the cost of the transmission system is equitably allocated between Federal and non-Federal power utilizing the system. A cost-of-service analysis (COSA) is conducted to determine what portion of the total revenues should be recovered from the various classes of service, including non-Federal utilities utilizing the transmission system. Transmission rates are designed to recover the costs associated with the transmission of non-Federal power. Other objectives considered in the development of the proposed rates include conformance with legislative requirements, conformity to prudent utility practices, simplicity and ease of administration, rate continuity, the efficient development and use of regional transmission facilities, environmental impacts, and existing contract provisions. These rates have been prepared in accordance with Bonneville's statutory authority to develop rates, 16 U.S.C. 832, 837e, 838, and the Pacific Northwest Electric Power Planning and Conservation Act, (Pub. L. 96–501, 16 U.S.C. 839 et. seq., Regional Power Act or Regional Act).

On May 25, 1979, Bonneville published in the **Federal Register** a Notice of "Intent to Revise Transmission Rates; Request for Public Comment" (44 FR 30405). In response to such Notice, Bonneville received comments and recommendations from interested persons and customers. In addition, Bonneville held customer workshops in December 1980 which allowed customers and others the opportunity to comment upon various transmission rate matters. All comments were reviewed and considered in the development of the rates proposed in this Notice. Continued public involvement will be encouraged throughout the rate hearings.

In conjunction with the development of revised transmission rates, Bonneville is initiating a process to formulate a transmission service policy. The initial stages of the policy development process will coincide with the rate hearing process. Bonneville's announcement of its intent to formulate a transmission policy is being published in a separate Notice. The separate Notice seeks suggestions and recommendations on all aspects of transmission service policy.

I. *Rules of Procedure Governing Rate Adjustments and Public Participation.* Section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act provides for new procedures for encouraging the participation of the public in the development of Bonneville's rates. Since these procedures outlined in the Regional Power Act differ from Bonneville's published "Procedure for Public Participation in Marketing Policy Formulation" (45 FR 73531, November 5, 1980) and also differ from the procedure which governed the 1979 rate filing, Bonneville has prepared Rules of Procedure Governing Rate Adjustments (46 FR 11697, February 10, 1981) which are summarized herein and which Bonneville will use to develop both the wholesale power and transmission rates.

The Regional Power Act prescribes **Federal Register** Notice, one or more hearings, the opportunity to submit written views, data, questions, and arguments outside the hearings, a decision by the Administrator based on the record developed during the rate process, and transmission of the final rate proposal to FERC for confirmation and approval or to the Secretary of Energy.

The Procedures developed by Bonneville expand on these requirements. They provide for publication of Notice, a prehearing conference, hearings, receipt of written comments, preparation of decision documents, a decision, and the transmittal of the decision with supporting documentation to the Federal Energy Regulatory Commission (FERC) and to the Secretary of Energy.

The process begins with publication of a Notice, which may follow or be combined with a Notice of Intent and which includes the proposed rates, a listing of the research, studies, analyses, and other available information in support of the proposed rate, the deadline for claiming status as "party," and the beginning date for the hearings. This Notice satisfies that requirement.

The process provides further for a Prehearing Conference, if scheduled by the Hearing Officer. The Prehearing Conference for these proposed rates is scheduled for February 25, 1981, in the West Ballroom, Red Lion Lloyd Center, 1000 NE. Multnomah, Portland, Oregon. Issues which may be raised for discussion at the Prehearing Conference could include disputes concerning status as a party, the scope of cross-examination, hearing schedules, and other pertinent matters.

Registration for the hearings will begin at 8:30 a.m. and the hearings will commence at 9 a.m. on Monday, March 2, 1981, with a technically oriented presentation of the transmission and wholesale power rate proposals by the Bonneville rate staff. Clarifying questions will be permitted.

After the conclusion of the staff presentation, Bonneville will convene a series of hearings in locations outside Portland. The purpose of these hearings is to present to the public and to other interested persons a condensed form of the Bonneville staff case and to receive the comments, views, and opinions of the general public. The public's comments will be subject to cross-examination. Presentation of testimony and evidence from formal parties will not be allowed at these sessions.

Bonneville plans to hold five such hearings, which will be held at the times and locations and on the dates previously listed.

Bonneville will hold a sixth hearing on Friday, March 13, 1981, in San Francisco, California.

The conduct of the hearings will differ from the conduct of the Public Information and Comment Forums held during the 1979 rate process. However, the purpose of the hearings remains to develop a full and complete record and to receive public comment on the proposed rates.

Bonneville finds it necessary to distinguish between "participants" in and "parties" to the hearings. During the field hearings, Bonneville will receive comments, views, opinions, and information from "participants," who are defined in the procedures as interested persons who may express their views at a hearing but who may not cross-examine other witnesses, participate in prehearing conferences, or serve or be served with documents. This category of interest is being established to give the public the maximum opportunity to participate and have its views considered without assuming the obligations incumbent upon the "parties." The second category of interest is that of a "party." A party may be either a party of right because of its legal, contractual relationship with Bonneville, and hence, its direct interest, or it may be a person seeking to represent a significant and otherwise unrepresented public interest in the hearings. Parties may participate in prehearing conferences, may call and cross-examine witnesses, and are entitled to service of documents from all other parties. Parties may also be cross-examined and may be required to serve documents on the other parties. Cross-examination by parties may be limited by the Hearing Officer and is also limited by the requirement in the proposed procedures that parties of like interest cross-examine through one person. Participation by the parties will not occur at the field hearings but will occur later in the hearing process.

Bonneville expects that the field hearings will be followed by the cross-examination of the Bonneville staff, by the presentation of the cases of the other parties, and by opportunities for rebuttal and oral argument. The times and places will be established by the Hearing Officer at the Prehearing Conference and will be announced in a notice which will be mailed to all parties of record. In addition, Bonneville expects that the hearing will be continued to offer an opportunity for the receipt or development of additional information which may be valuable in the preparation of the Final Rate Proposal.

Persons need not attend the hearings in order to have their views included in the record. Written comments may be included in the record if they are submitted before the close of the hearings. Written views, data, questions, and arguments should be submitted to the Bonneville Public Involvement Coordinator. Material submitted for the record but outside the hearing sessions will not be subject to cross-examination.

The record will include the transcripts of the hearings, written material submitted by the customers and the public, documents developed by the Bonneville staff, and other material accepted into the record by the Hearing Officer. Based on the record as established, the staff will prepare an Evaluation of the Record which it will submit to the Hearing Officer. The evaluation will contain a summary of the major comments, criticisms, support, and alternatives offered to the proposed rate and a recommendation for their acceptance or rejection.

The Hearing Officer will then review the Record, will supplement it if necessary, and will certify the Official Record to the Administrator for decision.

The Administrator will develop the Final Proposed Rates based on the record certified by the Hearing Officer. The basis for the Final Proposed Rates will be supported by the Administrator's Record of Decision. The Administrator will serve copies of the Evaluation of the Record and the Administrator's Record of Decision upon all the parties and will file the Final Proposed Rates together with the Official Record with FERC for confirmation and approval. If FERC does not have final procedures in place for granting interim approval, Bonneville will also file the Final Proposed Rates and the Official Record with the Secretary of Energy.

II. *Other General Information.* Several of Bonneville's major contracts with utilities for transmission service allow rate adjustments not more frequently than once every 3 years; however, a negotiated change is being offered which reduces the rate adjustment period to 1 year. The current transmission rates were approved on an interim basis, subject to refund, on June 10, 1977. Therefore, under current contract provisions, new rates can become effective at any time after July 1, 1980. Under the Regional Power Act, FERC is given express interim approval authority. If FERC does not have interim approval procedures in place, the Secretary of Energy may continue to grant interim approval of rates to be effective through July 1, 1982. Bonneville anticipates filing the final transmission rate proposal with FERC on or about June 1, 1981. It is anticipated that Bonneville's new transmission rates will become effective on an interim basis on or about July 1, 1981. The final rate proposal will be developed after considering recommendations received from the public and may incorporate updated cost and revenue information. Therefore, the final rates filed with the FERC may differ from the current proposal.

The following major studies and other information used in the development of the proposed transmission rates will be available for review after February 24, 1981, at Bonneville Headquarters Building located at 1002 NE. Holladay Street, Portland, Oregon. The studies may also be requested by phone or in writing from Bonneville's Public Involvement Coordinator and will be available at the prehearing conference.

1. Cost-of-Service Analysis and Summary Version of Repayment Study.
2. Long-Run Incremental Cost Study.
3. Time-Differentiated Pricing Analysis.
4. Transmission Rate Design Study.
5. Environmental Determination.

III. *Proposed Rate Schedules and General Rate Schedule Provisions:* The current Formula Power Transmission Rate Schedule (FPT-1) reflects the provisions of numerous contractual agreements between Bonneville and its customers both in terms of the service provided and the rate form. The services provided under FPT-1 related contracts are typically specific as to points of delivery and integration, contract demand, determination of losses, and other matters. In addition, FPT-1 incldudes a variety of rate components specified by contract provisions. Such components include a distance for mileage charge and various terminal and facilities charges.

In light of the comments received from various parties, particularly Bonneville's transmission customers, Bonneville has reviewed the nature of the existing contractual agreements with respect to both service and rate form. While the transmission services and rate forms provided by Bonneville have in the past proven satisfactory in many respects, it has become apparent that alternative concepts may also be appropriate and desirable. Accordingly, Bonneville is proposing to offer a modification of previously employed transmission service provisions and rate forms so that a more uniform type of service will be available.

As the establishment or modification of transmission policy on a

comprehensive basis necessarily involves considerable consultation with existing and potential transmission customers and others, Bonneville is initiating a formal transmission policy development process. Bonneville's intent to initiate the policy development process is being announced by a separate Notice of Intent to Revise Transmission Policy. It is anticipated that in its first stages the transmission policy development process will coincide with the hearings on the proposed transmission rates. The comments received in the transmission rate hearings will be used in developing a proposed transmission policy. Following the development of a proposed transmission policy, separate public forums will be held and Bonneville will adopt a final transmission policy.

This rate proposal contains rate schedules which Bonneville intends to offer to customers along with an interim uniform type service. Bonneville anticipates that this interim service will prmit multiple network delivery points without additional charges, will not be restricted by direction of flow and will be coupled with a single uniform capacity rate. Furthermore, the contractual service provisions regarding loss determination are expected to be standardized, possibly on the basis of a uniform percentage of the energy transmitted. The modified service, uniform rate, and loss determination method will be available for all those transmission customers who elect to receive service under new interim contracts which include provisions consistent with the characteristics of the modified service, and which offer the opportunity to test a different rate methodology without long term commitment, during the time before development of the transmission policy. For each utility the interim contracts would include all firm transmission agreements, except Columbia Storage Power Exchange agreements and other agreements, if any, specified by Bonneville.

Accordingly, this transmission rate proposal includes two sets of rate schedules, Set A and Set B. The first set of schedules, Set A, consists of schedules designated FPT–2, ET–2 and UFT–2 which are similar in form to the currently effective rates and, therefore, are consistent with the rate provisions included in many existing contracts. The FPT–2 schedule does include provisions for partial-year service, a service which is not provided for under the existing FPT–1 rate schedule. In general, Set A rates will be applicable to the services provided under existing contracts. The second set of schedules, Set B, consists of two rate schedules designated IR–1 and IS–1 which involve networkwide transmission service and intertie transmission service, respectively. Each schedule employs a single uniform capacity rate. A transmission customer electing to retain the service, rate form, and loss determination provisions of existing contracts would utilize Set A rates. For those parties electing to avail themselves of the alternative transmission service and the standardized loss determination methodology offered by Bonneville under interim contracts for the period prior to the development of the transmission policy, Set B rates will be applicable along with the UFT–2 and ET–2 rate schedules for use-of-facilities arrangements and nonfirm energy transmission. So as to provide transmission customers with an opportunity to receive service under Set B rates without permanently terminating existing contracts and to provide a period for development of a long-range transmission policy, Set B service and rates will be available for a 1-year trial period after which time a customer can choose to return to Set A service and rates or opt for the service identified in the final transmission policy formulated during the 1-year trial period.

Set A Rates

Schedule FPT–2—Formula Power Transmission

Section 1. *Availability:* This schedule is available under Agreements which provide for firm transmission of electric power and energy using the Integrated Network Segment, and/or the PNW–PSW Intertie Segment. This schedule is for full-year and partial-year service and for either continuous service or intermittent service so long as a firm availability of service is required.

Section 2. *Rate:*

A. *Full-Year Service:* The monthly charge per kilowatt of Transmission Demand shall be one-twelfth of the sum of the Main Grid Charge, the Secondary System Charge and Intertie Charge, as applicable and as specified in the Agreement.

1. *Main Grid Charge:* The Main Grid Charge shall be the sum of one or more of the following factors as specified in the Agreement:

a. Main Grid Distance Factor—The amount computed by multiplying the Main Grid Distance by $0.0186 per mile;

b. Main Grid Integration Terminal Factor—$0.16;

c. Main Grid Miscellaneous Facilities Factor—$0.96;

d. Main Grid Terminal Factor—$0.16; and

e. Main Grid Delivery Terminal Factor—$0.34.

2. *Secondary System Charge.* The Secondary System Charge shall be the sum of one or more of the following factors associated with deliveries at 115 kV as specified in the Agreement:

a. Secondary Transformation Factor—$1.36;

b. Secondary System Integration Terminal Factor—$0.41;

c. Secondary System Distance Factor—The amount determined by multiplying the Secondary System Distance by $0.0762 per mile;

d. Secondary System Intermediate Terminal Factor—$0.41;

e. Secondary System Delivery Terminal Factor—$0.42.

3. *Intertie Charge*—for use of Intertie facilities—$3.27.

B. *Partial-Year Service:* The monthly charge per kilowatt of capacity shall be as specified in Section 2.A. for all months of the year except:

1. For unplanned firm service, such as emergency station service when a generating unit is down, the yearly charge shall be equal to one monthly charge as defined in Section 2.A. so long as the use during each year does not exceed 730 hours. If the use during each year exceeds 730 hours, the yearly charge shall be as specified in Section 2.A.

2. For agreements whose term is 5 years or less and which specify service for fewer than 12 months per year, the charge shall be:

a. during months for which service is specified, the monthly charge defined in Section 2.A., and

b. during other months, the monthly charge defined in Section 2.A. multiplied by 0.2.

Section 3. *Determination of Transmission Demand:* Unless otherwise stated in the agreement, the factor to be used in determining the kilowatts of Transmission Demand is the largest of:

A. the Transmission Demand specified in the Agreement;

B. the highest Measured or Scheduled Demand for the month; or

C. the highest Measured or Scheduled Demand during the previous 11 months.

Section 4. *General Provisions:* Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; the Pacific Northwest Electric Power Planning and Conservation Act; the General Wheeling Provisions, Form 3, and the General Transmission Rate Schedule Provisions.

The meaning of terms used in this rate schedule shall be as defined in the Agreement or any of the above Acts or Provisions which are attached to the Agreement.

Schedule ET–2—Energy Transmission

Section 1. *Availability:* This schedule is available for nonfirm transmission of non-Federal nonfirm electric energy using excess capacity of the FCRTS. This rate is not available for the transmission of energy that is used to meet firm obligations, nor for energy which cannot be interrupted.

Section 2. *Rates:* The charge for nonfirm transmission of non-Federal nonfirm electric energy shall be based on the following rates.

	Mills/kilowatt hours
1. Delivery Over Integrated Network	1.08
2. Delivery Over the PNW–PSW Intertie	1.28
3. Delivery Over PNW Intertie including use of PNW Transmission System	2.36

Section 3. *General Provisions:* Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; the Pacific Northwest Electric power Planning and Conservation Act; the General Wheeling Provisions, Form 3, and the General Transmission Rate Schedule Provisions. The meaning of terms used in this rate schedule shall be as defined in the Agreement or any of the above Acts or Provisions which are attached to the Agreement.

Schedule UFT–2—Use-of-Facilities Transmission

Section 1. *Availability:* This schedule is available for the firm transmission of electric power and energy over specified FCRTS facilities installed or operated primarily for the benefit or convenience of a limited number of customers. This schedule is not appropriate for new agreements for service over the Integrated Network Segment, or the PNW–PSW Intertie Segment.

Section 2. *Rates:* The monthly charge per kilowatt of Transmission Demand specified in the Agreement shall be one-twelfth of the Annual Cost per kilowatt of Capacity of the specified facilities. Such Annual Cost shall be determined in accordance with Section 3.

Section 3. *Determination of Transmission Rate:*

A. From time to time, but not more often than once in each Contract Year, Bonneville shall determine the following data for the facilities which have been constructed or otherwise acquired by Bonneville and are used to transmit electric power and energy thereunder:

1. Capital cost of each such facility as specified in the most recently published plant investment records of Bonneville which are issued in support of the Federal Columbia River Power System financial statement.

2. Annual Interest and Amortization Ratios for each such facility using the most recent system average cost factors developed from actual Interest and Amortization costs for specific categories of FCRTS facilities and from data included in the financial statement.

3. Operation, maintenance, administrative and general, and general plant costs of such facilities using the most recent system average costs for specific categories of FCRTS facilities.

4. The yearly noncoincidental peak demands of all users of such facilities.

B. The monthly charge per kilowatt of Transmission Demand shall be one-twelfth of the sum of the Annual Cost per kilowatt of each of the FCRTS facilities used. The Annual Cost per kilowatt of each facility constructed or otherwise acquired by Bonneville shall be determined in accordance with the following formula:

$$(IxR) + B/D$$

Where B = Operation, maintenance, administrative and general, and general plant cost of such facility as determined in A.3.

I = Capital cost of such facility as determined in A.1.

R = Annual Interest and Amortization Ratio for such facility as determined in A.2.

D = The sum of the yearly noncoincidental demands on the facility as determined in A.4.

The Annual Cost per kilowatt of facilities listed in the Agreement which are owned by another entity, and used by Bonneville for making deliveries to the Transferee, shall be determined from the costs specified in the Agreement between Bonneville and such other entity.

Section 4. *Determination of Transmission Demand:* Unless otherwise stated in the Agreement, the factor to be used in determining the kilowatts of Transmission Demand shall be the largest of:

A. The Transmission Demand specified in the Agreement;

B. The highest Measured or Scheduled Demand for the month, the Measured Demand being adjusted for power factor; or

C. The highest Measured or Scheduled Demand during the previous 11 months.

Section 5. *General Provisions:* Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; the Pacific Northwest Electric Power Planning and Conservation Act; the General Wheeling Provisions, Form 3, and the General Transmission Rate Schedule Provisions. The meaning of terms used in this rate schedule shall be as defined in the Agreement or any of the above Acts or Provisions which are attached to the Agreement.

Set B Rates

Schedule IR–1—Integration of Resources

Section 1. *Availability:* This schedule is available only to those utilities who agree to convert all their Firm Transmission Agreements, except Columbia Storage Power Exchange (CSPE) and other agreements, if any, specified by Bonneville, in order to comply with the integration transmission service.

Section 2. *Service:* All non-Federal electric power scheduled to be integrated by the Network Segment of the FCRTS receives a uniform Network-wide service which is not limited by characteristics of generation, transmission facilities expected to be used, or special historical services or limitations. Integrated power, less average losses, will be delivered for a uniform network demand rate to any approved Network Segment point of delivery.

Section 3. *Billing Determinant:* The Billing Determinant is derived from the retroactive reports of the hourly amounts of energy made available to Bonneville pursuant to the utility Agreements. The hourly reports are combined into a single schedule for each utility and the maximum hourly demand occurring during the peak daily period (7 a.m. to 10 p.m., Monday through Saturday) is the Billing Determinant for the billing month.

Section 4. *Rate:* The monthly charge per kilowatt (kW) of Billing Determinant is $0.457.

Section 5. *General Provisions:* Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; the Pacific Northwest Electric Power Planning and Conservation Act; the General Wheeling Provisions, Form 3, and the General Transmission Rate Schedule Provisions. The meaning of terms used in this rate schedule shall be as defined in the Agreement or any of the above Acts or Provisions which are attached to the Agreement.

Schedule IS–1—INTERTIE SERVICE

Section 1. *Availability:* This schedule is available for power integrated by the Integration Schedule and transmitted over the Pacific Northwest—Pacific Southwest Intertie. The Rate identified in Section 4 below is in addition to the Rate given in the Integration of Resource Schedule (IR–1).

Section 2. *Service:* Service under this schedule is limited by intertie capacity, transmission capacity outside the Area, and existing transmission agreements. Integrated power, less average losses, will be delivered to or from the Oregon-California or the Oregon-Nevada state line.

Section 3. *Billing Determinant:* The Billing Determinant is derived from the retroactive reports of the hourly amounts of energy made available to Bonneville pursuant to the utility agreements. The hourly reports are combined into a single schedule for each utility and the maximum hourly demand occurring during the monthly billing period is the Billing Determinant for the billing month.

Section 4. *Rate:* The monthly charge per kilowatt (kW) of Billing Determinant is $0.546.

Section 5. *General Provisions:* Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; the Pacific Northwest Electric Power Planning and Conservation Act; the General Wheeling Provisions, Form 3, and the General Transmission Rate Schedule Provisions. The meaning of terms used in this rate schedule shall be as defined in the Agreement or any of the above Acts or Provisions which are attached to the Agreement.

General Transmission Rate Schedule Provisions

1. *Interpretation.* The provisions in the Agreement to which these General Transmission Rate Schedule Provisions (GTRSP) are attached as an exhibit shall be part of these GTRSP for the purpose of determining the meaning of any provision contained herein. If a provision in such Agreement is in conflict with a provision contained herein, the former provision shall prevail.

2. *Bonneville Service Area.* The Bonneville Power Administration (Bonneville) shall operate and maintain the Federal Columbia River Transmission System (FCRTS) within the Pacific Northwest and shall construct such improvements, betterments, system additions and replacements within the Pacific Northwest as it determines are appropriate and required to:

a. integrate and transmit "electric power" from existing or additional Federal or non-Federal generating units;

b. provide service to the Bonneville wholesale power and wheeling customers;

c. provide interregional transmission facilities; or

d. maintain the electrical stability and electric reliability of the Federal Columbia River Power System.

3. *Availability of Transmission Service.* Any capacity in the FCRTS which Bonneville determines to be in excess of the capacity required to transmit Federal power will be made available to all utilities on a fair and nondiscriminatory basis by the application of schedules identified in the Schedule of Transmission Rates, dated 1981 or as subsequently revised.

4. *Billing Details.*

a. The Transmission Billing Determinant is the electric power quantified by the method specified in the Transmission Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

b. Bills for transmission service will be computed and rendered monthly, generally on a calendar-month basis.

c. Bills not paid in full on or before the close of businesss of the twentieth day after the date of the bill shall bear an additional charge which is the greater of one-fourth percent (0.25%) of the amount unpaid or $50. Thereafter, a charge of one twentieth percent (0.05%) of the sum of the initial amount remaining unpaid and the additional charge herein described shall be added on each succeeding day until the amount due is paid in full. The provisions of this paragraph do not apply to bills rendered under contracts with other agencies of the United States.

Remittances received by mail shall be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the twentieth day after the date of the bill. If the twentieth day after the date of the bill is a Sunday or other nonbusiness day of the customer, the following day is the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the twentieth day shall bear a postal department cancellation in order to avoid assessment of such further charges.

Bonneville may, whenever a transmission bill or a portion thereof remains unpaid subsequent to the twentieth day after the date of the bill, and after giving 30 days' advance notice in writing, cancel the Agreement, but such cancellation shall not affect the customer's liability for any charges accrued prior thereto.

If Bonneville is unable to render the customer a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill, if so issued, shall have the validity of, and shall be subject to, the same payment provisions as a final bill. Failure to receive a bill shall not release the customer from liability for payment. Billings under each rate schedule application are rounded to whole dollar amounts, by elimination of any amount of less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

d. For an initial operating period, not to exceed 3 months, beginning with the commencement of operation of a new generating plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, Bonneville may agree to modify the measured or scheduled demand established for that period, or make other adjustments which are determined to be appropriate.

e. The transmission customer shall furnish Bonneville necessary information for making any computation required for the purposes of determining the proper charges for the use of the FCRTS and shall cooperate with Bonneville in exchanging such additional information as may be reasonably useful for respective operations.

5. *Definitions.* Capitalized terms that are used in the Transmission Rate Schedules shall be as defined below, or, if not so defined, as defined in the Agreement.

a. *Agreement:* The transmission agreement to which this exhibit is attached.

b. *Connection Point:* Refers collectively to the following:

(1) Point of Integration (POI): Connection points where a non-Federal project is integrated with the FCRTS.

(2) Point of Delivery (POD): Connection points where power is delivered to a customer from the FCRTS. The power may be Federal or non-federal.

(3) Point of Exchange (POE): Connection points listed in an Exchange Agreement. Power may be delivered or received at POE without special accounting.

c. *Electric Power* (or simply Power if no confusion would result without a modifier of mechanical, chemical, or electrical): Electric peaking capacity (kW), or electric energy (kWh), or both.

d. *Firm Transmission Service:* Firm availability of transmission service for any power scheduled or otherwise made available, limited only by the amount and time period specified in the Agreement. Firm transmission service is supplied for all types of power, such as firm, nonfirm exchange, interruptible, or other.

e. *Main Grid:* That portion of the FCRTS with facilities rated 230 kV and higher, exclusive of the Intertie.

f. *Main Grid Delivery Terminal:* 230 kV Terminal Facilities associated with a Point of Delivery.

g. *Main Grid Distance:* The distance in airline miles on the Main Grid between the Point of Integration and the Point of Delivery, multiplied by 1.15.

h. *Main Grid Integration Terminal:* The Main Grid Terminal Facilities located at the Point of Integration.

i. *Main Grid Miscellaneous Facilities:* Switching, transformation and other backup facilities of the Main Grid required to integrate the Main Grid.

j. *Main Grid Terminal:* Terminal facilties on the Main Grid adjacent to the Secondary System.

k. *NonFirm Transmission Service:* Service for which Bonneville will accpet power only when it determines excess capacity is available. Once Bonneville accepts power for transmission service, the service provided is the same for firm and nonfirm transmission service.

l. *Secondary System:* That portion of the FCRTS facilities with operating voltage of 115 kV or 69 kV, exclusive of Main Grid facilities, Intertie facilities, and lower voltage (less than 69 kV) FCRTS facilities which may be used on a use-of-facility basis.

m. *Secondary System Delivery Terminal:* A Point of Delivery from a Main Grid substation at 115 kV or 69 kV, or a terminal located at a Point of Delivery from the Secondary System.

n. *Secondary System Distance:* The number of circuit miles of Secondary System transmission lines between the Main Grid and the Point of Delivery or the lower voltage FCRTS facilities which may be used on a use-of-facility basis, as specified in the Agreement.

o. *Secondary System Integration Terminal:* The first Terminal Facility in the Secondary System.

p. *Secondary System Intermediate Terminal:* The final Terminal Facilities in the Secondary System.

q. *Secondary Transformation:* Transformation from Main Grid to Secondary System facilities.

6. *General Provisions:* Transmission Rate Schedules and General Transmission Rate Schedule Provisions of the Bonneville Power Administration, effective July 1, 1981, supersede in their entirety Bonneville's Transmission Rate Schedules and General Transmission Rate Schedule Provisions effective June 10, 1977.

IV. *Major Concepts and Issues:* Bonneville has prepared several studies in the process of developing the transmission rates presented in this Notice. The following description of these studies and discussion of the issues considered in the rate development process will be divided into sections on repayment, cost of service, rate design, and other concerns.

a. *Repayment Study.* The Bonneville Project Act, the Transmission System Act and the Regional Power Act set out criteria which requires that Bonneville produce revenues sufficient to recover the cost of producing, acquiring, conserving, and transmitting the electric power that Bonneville markets, to recover the cost of transmitting power for other parties, and to repay with interest the Federal investment in transmission and generation facilities in the FCRPS. The repayment study projects estimated revenues and costs over the repayment period for the entire power system to determine if there will be enough revenue to cover all costs. The assumptions used in the repayment study are detailed in the Cost-of-Service Analysis. Passage of the Regional Power Act in December 1980 required Bonneville to make a supplementary analysis of the Regional Power Act costs which were not included in the original repayment study. The repayment study used to develop the final rate proposals will include all appropriate costs and revenues.

Interest and amortization costs for the FCRPS are identified in the repayment study and are properly considered when determining revenue level for all classes of service. The initial rate propoal is based on cost estimates and assumptions of the repayment study and COSA. If any of the estimated projections of loads, costs, or streamflow conditions are not accurate, Bonneville may experience revenue surpluses or shortages. Small temporary revenue shortages can be dealt with by deferring interest and amortization payments on appropriated funds and can be repaid in years with surplus revenue. Sound business principles dictate that this practice should only be a temporary means of satisfying cash shortages.

Due to higher than projected costs and reduced revenues, it is projected that by the close of fiscal year 1981 the accumulated deficit of unpaid annual obligations will be $151 million. Since any accrued deficiency in amortization must ultimately be repaid in order to satisfy Bonneville's statutory obligations, Bonneville is considering options both to cover the accumulated deficit and to avoid the continued deferment of forecasted amortization payments. These options may cause Bonneville's revenue requirement to increase beyond the level identified in the current proposal. Bonneville anticipates that this item will be considered in the preparation of cost data and development of policy for the final repayment studies supporting the final transmission and wholesale rate proposals.

Bonneville is soliciting comments from the public pertaining to the treatment of this accumulated deficit. Analysis of this problem is continuing in order to identify the optimal repayment method, but no recommendation has yet been made by Bonneville staff.

b. *Cost-of-Service Analysis (COSA).* The COSA, along with certain adjustments detailed in the Transmission Rate Design Study, is designed to determine the cost of providing service to various classes of customers and is used as a basis for evaluating the adequacy of the various power sales and transmission rates currently in effect. Thus, the COSA is used in demonstrating that the proposed rates will equitably recover transmission costs from Federal and non-Federal power utilizing the FCRTS.

1. *Test Year:* The COSA procedure begins with the selection of a test year and the determination of the investment and operating expenses involved in providing service in such test year. The COSA developed to support the initial transmission rate proposal and the initial 1981 wholesale power rate proposal uses a Fiscal Year (FY) 1982 test year. For the initial transmission rate proposal, the FY 1982 test year was selected, in part, because it is the period for which cost estimates are most easily derived. Furthermore, FY 1982 closely matches the initial 12-month period the rates are anticipated to be in effect. However, as several existing transmission agreements preclude rate increases more frequently than once every 3 years, it is anticipated that the proposed rates will be in effect through FY 1984 absent contract modifications to permit more frequent rate adjustments. Accordingly, the use of a FY 1983 test year and other alternative cost projection concepts are being

considered for use in developing the final transmission rate proposal.

2. *Functionalization:* In utility cost analyses, investment and operating costs are typically grouped by the functions the utility performs. For Bonneville these functions have been identified as generation, transmission, and metering and billing. A direction-of-effort study was performed to determine how certain facilities and operating expenses should be functionalized. To accomplish this, managers in each Bonneville organization identified both the percentage of staff effort expended on each of the three functions and the functional use of facilities. The application of the results of the direction of effort study to the test year cost estimates yields functionalized cost data.

3. *Classification:* Classification refers to the process by which costs are associated with either usage at the time of system peak (capacity), or total usage during a time period (energy). The approach that is commonly used to classify transmission costs is known as the fixed-variable method. Using this method, transmission costs are classified 100 percent to capacity based on the view that peak usage, not variable energy usage, determines the necessary transmission plant investment. In the COSA supporting this proposal, all transmission costs were classified to capacity.

Bonneville has considered utilizing the cost causation approach to classify transmission costs. This would result in some costs being classified to energy because certain investment decisions, principally those associated with conductor sizing and larger towers, are influenced by the desire to reduce losses and are affected by the volume of anticipated energy deliveries. Preliminary staff analysis indicates that some portion of the transmission system costs are related to energy deliveries. However, an acceptable methodology for the classification of transmission costs to energy has not been developed. Therefore, the traditional fixed-variable cost method of classifying transmission costs entirely to capacity was adopted for this COSA. Bonneville specifically invites suggestions for methodologies for classifying transmission costs.

4. *Segmentation:* Although Bonneville operates a regionwide transmission system, some segments of the FCRTS are not needed to provide service to certain classes of customers. To better assure an equitable allocation of the costs of the FCRTS among all classes of service, the FCRTS has been divided into seven segments so that the costs of each segment can be separately identified and allocated in relation to the service being provided. Portions of the costs of only two of the seven segments, integrated network and intertie, are allocated to transmission customers with adjustable rates. The seven transmission segments are: Integrated network, Pacific Northwest-Southwest intertie, generation integration, fringe area facilities, preference customer delivery facilities, direct-service industrial customer delivery facilities, and investor-owned utility delivery facilities.

5. *Allocation:* After transmission costs are functionalized, segmented, and classified, Bonneville uses the Monthly Peak Responsibility Method (12 CP) to allocate costs to each cutomer class. Bonneville has chosen the 12 CP method to allocate costs for various reasons including: (1) The 12 CP method recognizes diversity and the integrated nature of the transmission system, (2) the 12 CP method reflects the use of Bonneville's sytem to transmit energy throughout the year, and (3) Bonneville's firm transmission loads, power and transmission, are fairly uniform throughout the year.

The 12 CP allocation factors used in the COSA are calculated from the power flowing on the system according to contractual arrangements.

c. *Transmission Rate Design:* In the design of transmission rates there are various concepts and issues which affect all rates, plus concepts and issues which relate specifically to Set A and Set B rates. The general matters affecting all classes of service are discussed first. The matters related to each rate schedule are discussed separately. Because the proposed rates reflect the results of the COSA, the matters related to that study are pertinent to rate design, but the discussion of those issues will not be repeated in this section.

1. General Concepts and Issues: The revenues in excess of allocated costs associated with the Wholesale Nonfirm Energy Rate (NF–1) and Energy Transmission Rate (ET–2) are credited against the allocated costs of service derived in the COSA. The credit from the nonfirm energy rate has been functionalized between generation and transmission by identifying the transmission portion as being equal to the average cost per kilowatt-hour of transmitting energy for other power services (2 mills/kWh), times the estimated nonfirm energy sales. The transmission credit so derived has been divided among the segments in proportion to the segmentation of total transmission costs. The revenues in excess of costs associated with nonfirm energy have been credited both to generation and transmission because both types of facility are involved in providing the service and, therefore, the costs related to both should be credited. The revenues in excess of costs associated with nonfirm enrgy transmission have been credited entirely to transmission because only transmission facilities are used in providing the service. This credit has been segmented in the same manner as the transmission credit for nonfirm energy sales.

Bonneville provides transmission services to certain customers at rates which, by contract, cannot be changed. Because the FCRPS rates must collect revenues sufficient to recover all costs, including those related to contracts for which rates cannot be increased, any revenue deficiency must be assigned to other customers. Fixed rate transmission services include the transmission of Columbia Storage Power Exchange (CSPE) power. As CSPE arrangements benefit all power sales customers, the revenue deficiency is assigned to power sales customers. Another transmission service for which the rates are fixed involves power from Tacoma City Light's Mayfield-Mossyrock projects. The deficiency from this transaction is shared by all classes of service in proportion to the class transmission allocation factors.

Power and energy losses associated with the provision of transmission service have historically been treated by Bonneville as a contract matter. With the limited exception of the existing schedule for Energy Transmission (ET-1), Bonneville has not viewed loss provisions as an appropriate item to be included in rate schedules. While it is anticipated that Set B services and rates will include a respecification of contractual loss provisions, the rate schedules included in this proposal do not include loss provisions.

The criteria for undertaking investments in transmission facilities is multifaceted and complex. Bonneville does, however, construct and place some facilities in service which are needed in large part for future use, not for use in the initial period the facilities are on line. This practice regarding the timing of system additions is undertaken both to minimize the cost of system additions and for environmental reasons. Although such facilities certainly provide benefits to current users through increased system reliability and other benefits, the primary cause of such investment relates to future system conditions. Neither the COSA nor the Transmission

Rate Design Study attempts to isolate the costs related to transmission facilities needed for the future.

Another factor considered in the design of the alternative transmission service and rates has been the desirability of sharing the benefits and risks of the FCRTS with all customer groups. With Bonneville's extensive transmission system which is utilized by many parties, it is often difficult to associate benefits or risks of constructing and maintaining that system with specific entities and specific contractual arrangements. Therefore, a more comprehensive and less situation specific approach has been utilized in developing Set B rates and the related service concepts.

In keeping with the principles included in many contractual arrangements, both the COSA and the Transmission Rate Design Study treat the FCRTS as a system which is distinguishable from other Pacific Northwest transmission facilities in terms of both costs and loads. The analysis supporting this proposal does not attempt to treat total Pacific Northwest transmission system costs or loads, but rather deals only with the FCRTS. While the approach used in the proposal is consistent with frequently used ratemaking and contractual practices, Boneville has explored the merits of treating the entire Pacific Northwest transmission system as a unified whole for ratemaking purposes. Such an approach would result in all parties utilizing the combined Pacific Northwest transmission system, including Bonneville, being assessed a portion of the total system cost in proportion to both the load a party places on the total system and the investment each party has made in the total system. Bonneville is continuing to investigate this method of establishing proportional cost responsibility.

2. Specific Concepts and Issues:

Set A Rate Schedules. The rate schedules included in Set A are designed to reflect the form of the existing schedules because in many cases such rate form is prescribed by contract provisions. The form of the FPT–2 rate includes a distance or mileage component and various terminal charges. While the COSA is the basis for determining the class revenue requirement for FPT–2, and IR–1 and IS–1, the COSA cost allocation does not reflect the billing determinants used in FPT–2. Distance is not recognized in the COSA as a cost factor, nor does the COSA separately identify the costs and use of specific types of facilities. Therefore, it is necessary to undertake a three-part process to design FPT–2 rates. The first step involves the development of unit cost information for the facilities treated in the required rate components. The unit costs are derived by using facility cost data, unadjusted for revenues from nonfirm energy and energy transmission sales. System use is based on a power flow simulation of the projected peak load period for the test year. Such power flow simulation does not specifically relate to the 12 CP allocation factor load data used in the COSA. In addition, the unit costs do not conform precisely to the billing determinants ultimately used in FPT–2. The second step involves applying such unit costs to the class billing determinants to determine the revenues produced by such rates. For numerous reasons, including those noted above, the FPT–2 revenues produced by the unit cost approach do not coincide with the COSA-based revenue requirement. Thus the third step in the process involves constraining the FPT–2 rates produced by the unit cost approach to the COSA-based revenue requirement. The constraining of FPT–2 rates to produce the appropriate class revenue requirement has been accomplished by modifying all of the FPT–2 rate components by a uniform percentage (approximately 58 percent). The FPT–2 schedule makes provisions for partial-year service. The rate for partial-year service is the same as for full-year service during the months for which service is specified. During months in which service is not specified, the charge is 20 percent of the full-year rate.

Both Set A and Set B include a schedule for energy transmission (ET–2) and, as this class of service is not allocated costs in the COSA, it is necessary to determine the level of the rate by other means. The technique used to develop the ET–2 rate is to calculate the unit cost per monthly coincidential peak kilowatt for the network and intertie segments, by dividing the total COSA-derived costs for those segments, adjusted for nonfirm energy revenues, by the estimated monthly coincidental peak kilowatts. The ET–2 rate is calculated by applying the unit cost per kilowatt to the estimated load factor of the ET class.

An additional schedule included in both Set A and Set B is Use-of-Facilities Transmission (UFT–2). This schedule contains a cost formula rather than a specific rate. The UFT–2 schedule is a continuation of the previous schedule in terms of its applicability to identifiable facilities. One change being proposed for UFT–2 involves calculating operating costs based upon average operating costs for the particular category of facilities rather than estimating such costs as a percentage of investment costs. Another change is that the costs of the facility will be divided among the users of the facility based on each user's noncoincidential demands.

Concurrent with this rate filing, Bonneville is also planning to eliminate the Z-factor credit. The Z-factor credit is a reduction in the billing determinant (contract megawatts) for those FPT customers who are also Federal power customers. The credit is included in the contracts and not in the rate schedule. The Z-factor was orginally included in contracts to recognize the diversity between a customer's transmission demands and power demands. Concurrent with the 1976 Transmission Rate Filing, Bonneville indicated that the Z-factor would be phased out: a 50-percent reduction at that time, to be followed by a complete elimination in the next transmission rate filing. In the allocation of transmission costs between Federal and non-Federal customers, full recognition is given to economies resulting from diversity on the transmission system. No further recognition is needed, and continuation of the Z-factor would result in those customers receiving double credit for diversity.

Set B Rate Schedules. Unlike FPT–2, which is a continuation of the existing contractual arrangements regarding service characteristic, rate form, and loss provisions, the IR–1 schedule of Set B involves a change in service to a more flexible and comprehensive service. The IR–1 service is not related to specific facilities and contract demand amounts but rather to network-wide service and actual recognized use of the FCRTS. The COSA-derived revenue requirements, as adjusted, and the concepts used in the COSA are reflected in the design of the rates included in the IR–1 and IS–1 rate schedules. Therefore, the calculation of these rates does not require the additional steps needed in the computation of the rate components included in FPT–2. The IR–1 rate is calculated by dividing the $31,716 million COSA-adjusted revenue requirement for the class by the appropriate billing determinants (5788MW) to derive the charge of $0.457 per kilowatt month. Similarly, for IS–1, the $1.342 million class revenue requirement related to the intertie is divided by the billing determinants (205 MW) to yield a charge of $0.546 per kilowatt month.

The IR–1 rate has been time differentiated diurnally in a manner similar to the transmission component of certain revised wholesale power rates.

The IR–1 rate is only to be applied for service between 7 a.m. and 10 p.m., Monday through Saturday. The time differentiation of the IR–1 rate recognized that results of Bonneville's Time-Differentiated Pricing Analysis and Long-Run Incremental Cost Study indicating that investment in transmission facilities is not a function of offpeak period conditions.

3. *Optional Rate Schedule Concept.* The FPT–2 schedule and the combination of the IR–1 and IS–1 schedules are both designed to recover the revenue requirement allocated to the firm transmission class. Utilities will be able to choose whether to remain on the FPT–2 schedule or enter into interim contracts incorporating the concepts included in the IR–1 schedule. It is anticipated that this process will result in a revenue deficiency, as utilities may choose the rate schedule which will yield the lower total charge for transmission service. Based on the assumption that minimizing their transmission charge would be the sole criterion, the deficiency would amount to approximately $3.8 million. However, no adjustments are being made to the initial proposal to eliminate this deficiency because of uncertainties concerning which utilities will switch to the IR–1 schedule. These uncertainties result from the expectation that both the services offered and the treatment of losses will likely be different in the IR–1 schedule and these differences may be more important criteria than transmission charges. Bonneville expects to investigate these concerns more and as a result of that investigation may include an adjustment for a projected revenue deficiency in the Final Proposal.

For the final proposal, Bonneville is considering a division of the firm transmission class based upon a best estimate of which utilities will switch to the IR–1 schedule. An allocation of costs between the rate subclasses would be made according to COSA allocation factors. The IR–1 and FPT–2 schedules would be developed to recover the allocated costs. Because the IR–1 billing determinants track the COSA allocation factors more closely than the FPT–2 billing determinates, it is expected that the final FPT–2 rate would absorb most of the deficiency caused by customers choosing to minimize transmission costs.

d. *Other Issues:* Bonneville has examined the environmental impacts of the proposed transmission rate increase and determined that this action does not require completion of an environmental assessment or an environmental impact statement. This determination was reached because the proposed increase in rates is less than the general rate of inflation since the last transmission rate increase, because the increase in transmission rates will not have any measurable impact on retail power charges, and because the increase in rates is not expected to be signifcant enough to warrant construction of parallel transmission facilities by Bonneville's transmission customers.

The impact of the proposed rates varies by customer and firm transmission schedule selected. For those customers electing to retain existing transmission contracts, the percentage increase in revenues from the FPT–2 schedules compared with the FPT–1 schedules varies from 34 to 116 percent with the average increase being 49 percent. The variation in the percentage change in revenues derivded from the IR–1 rate schedule compared with the FPT–1 rates ranges from a 25-percent decrease to a 350-percent increase with the average change being a 49-percent increase.

Bonneville has conducted a Long-Run Incremental Cost (LRIC) study to determine the incremental costs Bonneville is incurring to serve additions to peak loads, and a Time-Differentiated Pricing Analysis (TDPA) to determine how load and temperature affect the relative loading of the transmission system diurnally and seasonally. The results of these two studies have been incorporated into the design of the IR–1 rate.

Dated: February 10, 1981.

Earl Gjelde,

Acting Administrator.

[FR Doc. 81–5372 Filed 2–12–81; 11:00 am]

BILLING CODE 6450–01–M

Proposed Wholesale Power Rate Adjustment, Public Hearings, and Opportunities for Public Review and Comment

AGENCY: Bonneville Power Administration (Bonneville), Department of Energy.

ACTION: Notice of Proposed Wholesale Power Rate Adjustment, Notice of Public Hearings, and Opportunities for Review and Comment.

SUMMARY: The Pacific Northwest Electric Power Planning and Conservation Act (Regional Power Act or Act) enacted on December 5, 1980, expanded Bonneville's obligation to serve the electric load requirements of both the publicly-owned and investor-owned utilities of the Pacific Northwest Region and Bonneville's direct service industrial customers. The Act expands Bonneville's responsibilities and has made differences in the process and substance of Bonneville's rate development activities. The Regional Power Act confirms Bonneville's obligation to establish and periodically revise Bonneville's rates so that they are adequate to recover, in accordance with sound business principles, the costs associated with the production, acquisition, and transmission of electric power and to recover the Federal investment in the Federal Columbia River Power System (FCRPS).

Prior to December 5, 1980, Bonneville had determined an increase was needed in its existing wholesale power rates charged for electricity produced, acquired, and transmitted by Bonneville. At that time, revenues under existing rates for Fiscal Year (FY) 1982 were estimated to be $631.1 million. Considering both the increase in revenues that was necessary under the existing rate schedules, and the revenues from the additional power sales and power exchanges that will take place in FY 1982 as a result of the Act, Bonneville's total revenue requirement in FY 1982 is approximately $1.5 billion.

Bonneville is proposing to revise both its wholesale power and transmission rate schedules in order to produce sufficient revenues to fulfill its new statutory requirements. The proposed transmission rates are being published separately. The proposed wholesale power rates are presented in this Notice. Section 7 of the Regional Power Act directs the establishment of these rates to be applicable to all power sales provided for in the Act.

Opportunities will be available for interested persons to review the proposed rates and the supporting studies, to participate in hearings, and to submit written comments. During the development of the final rate proposal, Bonneville will evaluate all written and oral comments received in this process. Because of the consideration of public comments, or due to more current data, the final rate proposal may differ from the rates proposed in this Notice.

DATES: Persons wishing to become a formal "party" to the proceedings must notify Bonneville in writing of their intention to do so. The notification must be received by February 24, 1981, and should be addressed as follows: Hon. Dean F. Ratzman, Hearing Officer, Bonneville Power Administration, P.O. Box 12999, Portland, Oregon 97212. Power and Transmission customers of Bonneville are parties of right. Others may become parties by demonstrating in their notice and at the Prehearing

Conference that they would represent a significant and otherwise unrepresented public interest. The notice should contain: (1) The name of the person or entity claiming status as a party; (2) the person who will be representing the party; (3) whether the person or entity claiming status as a party has a contractual relationship with Bonneville which could be affected by the proposed rates; and (4) if no contractual interest exists, the interest the person believes would be served by their being a party. All timely applications will be ruled upon by the Hearing Officer.

Pursuant to the rate procedures, a Prehearing Conference will be held before the Hearing Officer at 9 a.m. on February 25, 1981, in the West Ballroom, Red Lion Lloyd Center, 1000 NE. Multnomah, Portland, Oregon.

The rate hearings will cover the transmission rates and the wholesale power rates and will begin with a technically oriented presentation of Bonneville's proposed wholesale power and transmission rates. Registration for the hearing will begin at 8:30 a.m. and the hearing will commence at 9 a.m. on March 2, 1981, in the Main Ballroom of the Masonic Temple, 1119 SW. Park Avenue, Portland, Oregon. The presentation of the staff case may continue into March 3 and 4, 1981. Clarifying questions will be permitted. Following the technical meetings, hearings will be held at locations outside Portland to present to the public a condensed form of the Bonneville staff case and to receive comments from the general public. The public's comments will be subject to cross-examination. Presentation of testimony and evidence from formal parties will not be allowed at these sessions. Registration for the hearings will be at 7 p.m., and the hearings will begin at 7:30 p.m. The dates and locations are: March 5, Parrish Middle School Auditorium, 802 Capitol Street NE., Salem, Oregon; March 9, Blackfoot Room, Village Red Lion, 100 Madison, Missoula, Montana; March 10, Training Office Auditorium, Boise Interagency Fire Center, 3905 Vista Avenue, Boise, Idaho; March 11, Federal Building, 3000 George Washington Way, Richland, Washington; and March 12, Snoqualmie Room, Seattle Center, 1st North and Republican Street, Seattle, Washington. Bonneville will hold a sixth hearing outside Portland on March 13, from 1 p.m. to 4 p.m., in Room 15018 of the Golden Gate Federal Building, 450 Golden Gate Avenue, San Francisco, California.

It is expected that during the Prehearing Conference, hearing dates will be set for cross-examination of the Bonneville rate staff, for the presentation of the cases of formal parties, and for rebuttal and oral argument. A notice of the dates and times of such hearings will be mailed to all parties of record. The hearing period may be continued for the presentation of other information which may affect significantly the Bonneville rate case, and for the taking of rebuttal testimony and cross examination regarding such information. Written comments may be submitted until the close of the hearings. The last day for receipt of written comments will be specified in a later Notice.

ADDRESSES: Written comments not submitted at the hearings should be submitted to the Public Involvement Coordinator, Bonneville Power Administration, P.O. Box 12999, Portland, Oregon 97212. Written comments submitted by the close of the hearing will be made part of the record.

FOR FURTHER INFORMATION CONTACT: Donna L. Geiger, Public Involvement Coordinator, P.O. Box 12999, Portland, Oregon 97212; (503) 234–3361, ext. 4261. Bonneville maintains toll-free lines for the use of persons within the region. Oregon callers may use 1–800–452–8429; callers in Washington, Idaho, Montana, Wyoming, Utah, Nevada, and California may use 1–800–547–6048. Messages and requests for information received outside of normal business hours (4:30 p.m. to 7:30 a.m.) may be recorded on the toll-free lines. Additional information is available from: Ronald H. Wilkerson, Spokane Area Manager, Room 561, U.S. Courthouse, West 920 Riverside Avenue, Spokane, Washington 99201, (509) 456–2518; Gordon H. Brandenburger, Kalispell District Manager, P.O. Box 758, Kalispell, Montana 59901, (406) 755–6202; Ronald K. Rodewald, Wenatchee District Manager, Room 314, U.S. Federal Building, 301 Yakima Street, Wenatchee, Washington 98801, (509) 662–4377; John H. Jones, Portland Area Manager, Suite 288, 1500 Plaza Building, 1500 NE. Irving Street, Portland, Oregon 97208, (503) 234–3361 ext. 4551; Ladd Sutton, Eugene District Manager, Room 206, U.S. Federal Building, 211 East 7th Street, Eugene, Oregon 97401, (503) 345–0311; Randall W. Hardy, Seattle Area Manager, 415 First Avenue North, Room 250, Seattle, Washington 98109, (206) 442–4130; Roy Nishi, Walla Walla Area Manager, West 101 Poplar, Walla Walla, Washington 99362, (509) 525–5500, ext. 701; Robert N. Laffel, Idaho Falls District Manager, 531 Lomax Street, Idaho Falls, Idaho 83401, (208) 523–2706.

SUPPLEMENTARY INFORMATION: On June 12, 1980, Bonneville published in the Federal Register a "Notice of Intent to develop Revised Wholesale Power Rates" (45 FR 34885). In May 1980, Bonneville announced at its customer meetings that preliminary studies indicated a 50-percent increase in Bonneville's overall revenue level was necessary, such increase to be effective July 1, 1981. The 50-percent estimate was board on a repayment study of the Federal Columbia River Power System (FCRPS). The repayment study tested the adequacy of revenues under existing rate schedules to meet Bonneville's obligations to recover the cost of producing and transmitting electric power and to repay with interest the Federal investment in the FCRPS as required by statute. At that time the repayment study was made, it was intended that wholesale power rates proposed by this Notice when combined with the transmission rates concurrently proposed, would be adequate to produce the necessary increase in the total revenues. However, passage of the Regional Power Act provided Bonneville with additional statutory obligations, along with a complete set of directives concerning the determination of the rates to be applied in carryng out its new, as well as existing, statutory obligations. Thus, it became necessary to propose revise rates that would not only recover Bonneville's revenue requirement as it was determined prior to the Act, but would also allow for the implementation of the various rate-related provisions of the Act.

There has not been sufficient time to completely redesign the process for development of the proposed rates to conform totally with the directives of the Act. Bonneville has not rerun the repayment study which indicated the need for a 50-percent revenue increase. Instead, the additional revenue requirement for FY 82 which is projected to occur as a result of Bonneville's increased responsibilities and obligations under the Act are identified and allocated to the appropriate customer classes in the Cost-of-Service Analysis. A repayment study will be run for use in development of the final rate proposal which will include consideration of all of Bonneville's obligations to recover costs and to repay with interest the Federal investment in the FCRPS.

The discussion of the major studies in Section IV.A. of this Notice indicates what portions of the studies will require revision, as a result of the Act before they can be used in the development of the final proposed rates. Every attempt

has been made in the preparation of this initial set of porposed rates to approximate the absolute and relative level of the various rates as they will appear in the final proposal. Bonneville has developed the proposed rates under a considerable time constraint. The agency believes that the requirements of the new law have been met and that the numerical calculations supporting the proposed rates will gain acceptance as additional time has been devoted to the study and explanation of the rates.

The proposed wholesale power rates have been prepared in accordance with Bonneville's statutory authority to develop rates, including the Bonneville Project Act of 1937, as amended, 16 U.S.C. 832e and f; 835j, k, and l; the Regional Preference Act, 16 U.S.C. 837d; the Federal Columbia River Transmission Act, 16 U.S.C. 838g and h, and the recently enacted Pacific Northwest Electric Power Planning and Conservation Act of 1980, Pub. L. 96–501, 16 U.S.C. 839 et. seq.

During the development of the repayment study and other studies, consideration was given to the comments and recommendations received from Bonneville's customers and the public in response to Bonneville's Notice of Intent.

In developing the proposed wholesale power rates, Bonneville considered revenue requirements, costs of service, marginal costs, conservation, environmental impacts, ease of administration, stability, continuty, value of service, ease of comprehension, and statutory obligations. The major studies which are prepared and which support the proposed wholesale rates will be available for examination on February 24, 1981, at the office of Bonneville's Public Involvement Coordinator, Bonneville Headquarters Building, 1002 NE. Holladay Street, Portland, Oregon. The studies may also be requested by phone or in writing from Bonneville's Public Involvement Coordinator and will be available at the Prehearing Conference. The studies are:

1. Cost-of-Service Analysis and Summary Version of Repayment Study.
2. Long-Run Incremental Cost Analysis
3. Time-Differential Pricing Analysis
4. Summary Rate Design Study

The environmental impacts of the proposed rates have alos been considered and documented in an Environmental Assessment which will be available for examination at the same location.

I. Rules of Procedures Governing Rate Adjustments and Public Participation

Section 7(i) of the Regional Power Act provides for new procedures for encouraging the participation of the public in the development of Bonneville's rates. Since these procedures outlined in the Act differ from Bonneville's published "Procedure for Public Participation in Marketing Policy Formulation" (45 FR 73531 November 5, 1980) and likewise differ from the procedure which governed the 1979 rate filing, Bonneville has prepared Rules of Procedure Governing Rate Adjustments (46 FR 11697 February 10, 1981) which are summarized herein and which Bonneville will use to develop both the wholesale power and transmission rates.

The Act prescribes a Federal Register notice, one or more hearings, the opportunity to submit written views, data, questions, and arguments outside the hearings, and a decision by the Administrator based on the record developed during the rate process.

Bonneville's procedures proposed by Bonneville expand on these requirements. They provide for publication of a Notice, a prehearing conference, hearings, receipt of written comments, preparation of decision documents, a decision, and the transmittal of the decision with supporting documentation to the Federal Energy Regulatory Commission (FERC) and the Secretary of Energy.

The process begins with publication of a Notice, which may follow or be combined with a Notice of Intent and which includes the proposed rates, and discussion of the research, studies, analyses, and other available information in support of the proposed rates, the deadline for claiming status as a "party," and the beginning date for the hearing. This Notice satisfies that requirement.

The procedure provides further for a Prehearing Conference if scheduled by the Hearing Officer. Pursuant to the rate procedures, a Prehearing Conference will be held before the Hearing Officer at 9 a.m. on February 25, 1981, in the West Ballroom, Red Lion Lloyd Center, 1000 NE. Multnomah, Portland, Oregon.

Issues which may be raised for discussion at the Prehearing Conference could include disputes concerning status as a party, the scope of cross-examination, hearing schedules, and other pertinent matters.

Registration for the hearing will begin at 8:30 a.m. and the hearings will commence at 9 a.m. on Monday, March 2, 1981, with a technically oriented presentation of the transmission and wholesale power rate proposals by Bonneville staff.

After the conclusion of the technical presentation, Bonneville will convene a series of hearings in locations outside Portland. The purpose of these hearings is to present to the public and to other interested persons a condensed form of the Bonneville staff case and to receive the comments, views, and opinions of the general public. The public's comments will be subject to cross-examination. Presentation of testimony and evidence from formal parties will not be allowed at these sessions. Bonneville plans to hold hearings at the times and locations previously listed.

The conduct of the hearings will differ from the conduct of the Public Information and Comment Forums held during the 1979 rate process. However, the purpose of the hearings remains to develop a full and complete record and to receive public comment on the proposed rates.

Bonneville finds it necessary to distinguish between "participants" in and "parties" to the hearings. During the field hearings, Bonneville will receive comments, views, opinions and information from "participants," who are defined in the proposed procedures as interested persons who may express their views at a hearing but who may not cross-examine other witnesses, participate in prehearing conferences, or serve or be served with documents. This category of interest is being established to give the public the maximum opportunity to participate and have its views considered without assuming the obligations incumbent upon the "parties."

The second category of interest is that of a "party." A party may be either a party of right because of its legal and/or contractual relationship with Bonneville, and hence, its direct interest, or it may be a person seeking to represent a significant and otherwise unrepresented public interest in the hearings. Parties may participate in prehearing conferences, may call and cross-examine witnesses, and are entitled to service of documents from all other parties. Parties may also be cross-examined and may be required to serve documents on the other parties. Cross-examination by parties may be limited by the Hearing Officer and is also limited by the requirement in the proposed procedures that parties of like interest cross-examine through one person.

Bonneville expects that the field hearings will be followed by the cross-examination of the Bonneville staff, by the presentation of the cases of the other parties, and by opportunities for rebuttal

and oral argument. The times and places will be established by the Hearing Officer at the prehearing conference and will be announced in a subsequent Notice that will be mailed to all parties of record. In addition, Bonneville expects that the hearing will be continued to offer an opportunity for the receipt and/or development of additional information which may be valuable in the preparation of the final rate proposal.

Persons need not attend the hearings in order to have their views included in the record. Written comments may be included in the record if they are submitted before the close of the hearings. Written views, data, questions, and arguments should be submitted to Bonneville's Public Involvement Coordinator.

The record will include the transcripts of the hearings, written material submitted by the customers and the public, documents developed by the Bonneville staff, and other material accepted into the record by the Hearing Officer. Based on the record as established, the staff will prepare an Evaluation of the Record which it will submit to the Hearing Officer. The evaluation will contain a summary of the major comments, criticism, support, and alternatives offered to the proposed rate and a recommendation for their acceptance or rejection.

The Hearing Officer will then review the Record, will supplement it if necessary, and will certify the Official Record to the Administrator for decision.

The Administrator will develop the final proposed rates based on the record certified by the Hearing Officer. The basis for the final proposed rates will be supported by the Administrator's Record of Decision. The Administrator will serve copies of the Evaluation of the Record and the Administrator's Record of Decision upon all the parties and will file the final proposed rates together with the Official Record with the FERC for confirmation and approval. If the FERC does not have final procedures in place for granting interim approval, the Administrator will also file the final proposed rates and the Official Record with the Secretary of Energy.

II. Elements of the Regional Power Act

The rate schedules contained in this publication are the first proposed in accordance with the new Act, which was signed into law on December 5, 1980. Prior to the Act, Bonneville allocated costs of resources from a single block, the FCRPS, and designed rates to recover those costs from limited classes of customers. Now, there are two additional distinct blocks of resource costs, and Bonneville's services extend to all classes of customers within the Pacific Northwest. Accordingly, the new rate schedules reflect many features contained principally in the Act's rate directives (Section 7), as well as the conditions related to classes of customers and services contained in the Act's power sales directives (Section 5).

Most importantly, the Act places on Bonneville a responsibility to all the electric power consumers in the Region. While protecting the historical preference and priorities of public bodies and cooperatives, there is a responsibility to provide, through time, parity in wholesale power costs to all residential and small farm consumers; to share the burdens, risks and benefits of meeting the load growth requirements of all requesting utilities; to provide a positive inducement to individual utilities to accept the considerable burdens of achieving conservation and developing generating resources; to accept the risks and costs of meeting the entire Region's present power supply deficits; and to provide access for all Bonneville's regional firm loads to the reserves provided by rights to restrict deliveries to industrial customers served directly by Bonneville.

A. *Services.*

The Act affirms that Bonneville's public body, cooperative, and Federal agency customers have a protected right to the full resources of the Federal Columbia River Power System. These customers will be able to have their current and future requirements met by Bonneville. In addition, the residential and small farm consumers of investor-owned utilities (IOU's) will receive the benefits of Bonneville's lowest cost resources and eventually will have wholesale power costs equivalent to those paid by similar consumers of preference customers.

The investor-owned utilities' net firm power requirements in the Region (in excess of their own firm resources in the year prior to the Act) can also be served by Bonneville if the utility seeks such service. These loads would be served at a different rate as described below, but would retain the benefits of system integration, reserves, risk sharing and nonfirm energy supplies.

Bonneville's existing direct-service industrial customers will receive new 20-year contracts for less than firm power. This will include significant rights of restriction in addition to those under existing contracts. These rights provide the Region with a major portion of the planning and operating reserves that help to keep costs lower to all of the Region's consumers.

B. *Costs.*

The Act identifies three distinct resource pools, commonly referred to as the Federal base system resources, the exchange resources under Section 5(c) of the Act, and new resources.

The first pool is comprised of Federal base system resources which the Act defines as (1) the FCRPS hydroelectric projects (present and future); (2) the resources acquired by the Administrator under long-term contracts in force on the effective date of the Act, and (3) the resources acquired as necessary to replace any reductions in capability of the components of (1) and (2). For the test year 1982, the Federal base system consists of the existing hydroelectric system, 30 percent of the output of the Trojan nuclear plant, portions of the power from the nuclear reactor at Hanford, and sufficient additional short-term purchased resources to make up for the lack of the Washington Public Power Supply System Projects 1 and 2 to the extent necessary to meet the Administrator's contractual obligations as of the date of the Regional Power Act. These are the same resources that would have been available to the Administrator to meet these firm power obligations prior to the Act. Therefore, the costs of these resources assigned to the customers paying them do not differ because of the Act.

The second resource pool consists of the power which Bonneville purchases from utilities, primarily IOU's, for the direct benefit of their residential and small farm consumers. The amounts of power purchased are a percentage of the residential and small farm loads of the individual utility beginning, with 60 percent in July 1981 and increasing by 10 percentage points annually. The Administrator is directed to acquire the power at the offering utility's average system cost for that year. The average system cost will be determined annually using a methodology currently being developed by Bonneville in consultation with its customers and state regulatory bodies in the Region and the Council established pursuant to Section 4 of the Act. (This methodology will be subject to review and approval by FERC). Bonneville must then sell an equivalent amount of power to the utility at the same rate that is in effect for sales of firm power to Bonneville's public body, cooperative, and Federal agency customers. The benefits of this "exchange" are to be passed through to the participating utility's residential loads within that State.

The third resource pool is the "new resource" pool. It will include all new resources developed, purchased, or otherwise acquired by Bonneville to

meet the load growth of investor-owned utilities plus any of thier firm power deficit in the year prior to December 5, 1980, which they ask Bonneville to meet. This pool also includes resources acquired to meet the new large load (Section 3(B) of the Act) requirements of Bonneville's public body, cooperative, or Federal agency customers. This pool will reflect the operational and cost advantages of blending the new resources with the secondary capability reserves of the existing Federal system. In addition, it should reflect the benefits of undertaking cost-effective conservation and of lower financing costs associated with spreading the risks of new resource development throughout the Region.

C. *Rates.*

The costs of the various resource pools described above plus the other costs incurred by the Administrator must be recovered in a manner described in Section 7 of the Act, including the provisions of other applicable law.

Section 7(b) directs the Administrator to establish rate or rates for power sold to meet the general requirements of the public body, cooperative, and Federal agency customers within the Region as well as power sold to participating utilities (Section 5(c)) for their residential and small farm consumers. Presently, the sum of these loads is less than the Federal base system (FBS) resources—the lowest cost block which Bonneville has available. In the future, as these loads exceed the FBS resources, the next lowest cost block of resources will be used for determining rates to these customers. In short, the preference customers and the residential and small farm consumers of participating utilities are assured of always receiving the lowest wholesale power cost from Bonneville. Moreover, the Act provides a specific rate test to assure, in general, that the preference customers will not pay more for wholesale power than they would have in the absence of the Act.

Rates for the direct-service industrial customers (DSI's) of Bonneville are governed by Section 7(c) of the Act. Before July 1, 1985, the rates to the DSI's are to be set at a level to recover the cost of the resources required to meet their loads including the net cost of the exchange provided under Section 5(c) of the Act. The DSI's yield their supplies of FBS resources associated with their service prior to the Act and replace it with supplies from the exchange purchases. In FY 1982 the exchange is limited to 60 percent of the IOU's residential and small farm loads in order to retain some FBS resources for the DSI's. Thus, for FY 1982, the DSI rate will recover costs which Bonneville pays for power from the utilities participating in the Section 5(c) exchange, as well as that portion of the FBS resources remaining to meet DSI load. The DSI's are, in effect, bearing the cost of the rate relief provided by the Act to the residential and small farm customers of the IOU's. A portion (approximately 25 percent) of the DSI load is supplied by nonfirm resources under average water conditions. The overall DSI rate reflects the costs of this service, plus a price which Bonneville would otherwise have received for this power. The rates to the DSI's will be adjusted pursuant to Section 7(c)(3) of the Act in recognition of the value of the planning and operating reserves through restriction rights on delivery of power to meet their loads.

Section 7(f) of the Act directs the establishment of rate or rates that will be charged for all other firm power sales made by the Administrator within the Region. Loads served under these rates may be the load growth or firm deficits on the IOU systems which Bonneville is obligated to serve under the Act if requested to do so by the individual IOU's. Section 7(f) rates also apply to service to preference customer's new large single loads as defined in the Act and which are excluded from service under the 7(b) rate. In designing the rates for test year 1982, all of the FBS resources and the exchange resources are identified as serving the loads provided for under Sections 7(b) and 7(c) of the Act. Therefore, the remaining new resource pool will be used to serve the load growth and large new single loads provided for in Section 7(f).

One significant service not treated in the rate directives of the Act is Bonneville's use and sale of nonfirm energy. Bonneville plans its long-term recovery of revenues on the basis of average water conditions. It also allocates few costs to the provision of those services. Consequently, the manner in which nonfirm energy is used, the rate that is set and the distribution of these revenues in excess of costs can have significant impacts upon the various classes of service. The revenues earned by sales of nonfirm energy goes, in general, to reduce the cost of firm power from the resources that produced, or contributed to the revenues. However, the cost reduction benefit of directly using the nonfirm energy rather than (and in displacement of) short-term purchases and higher incremental cost resources is a cost savings attributable to the cost pools containing these high cost resources. (Federal base system and new resource pools). The Bonneville proposal essentially provides that the preference customers and the residential and small farm consumers of participating utilities continue to receive those revenue benefits from nonfirm sales that are attributable to the Federal base system resources (including the revenue benefits from the direct use and displacement of these resources). In general, Bonneville will pursue nonfirm marketing policies which will provide benefits to all the consumers of the Pacific Northwest.

This extensive introduction to the Rate Proposal is made because Bonneville is well aware that its initial formulations of rate structures required to refect new and complex requirements will benefit from careful review and constructive comments. Bonneville requests its customers, State agencies, and the general public to consider the rate proposals in terms of their broad purposes and to provide recommendations that would improve upon our Region's ability to cooopeatively achieve those purposes.

III. Proposed Rate Schedules and General Rate Schedule Provisions

Schedule PF–1—Priority Firm Power Rate.

Section 1. *Availability:* This schedule is available for the purchase of firm power to be used within the Pacific Northwest for resale or for direct consumption by public bodies, cooperatives, Federal agencies, and investor-owned utilities participating in the exchange under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act. This schedule supersedes schedule EC–8 which went into effect on an interim basis on December 20, 1979, for public body, cooperative, and Federal agency customers.

Section 2. *Rate:*

a. *Demand Charge:*

(1) For the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $3.10 per kilowatt of billing demand.

(2) For the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $2.27 per kilowatt of billing demand.

(3) All other hours: No demand charge.

b. *Energy Charge:*

(1) For the billing months September through March: 5.9 mills per kilowatthour of billing energy.

(2) For the billing months April through August: 5.4 mills per kilowatthour of billing energy.

Section 3. *Billing Factors:* The factors to be used in determining the

billing for power purchased under this rate schedule are as follows:

a. For any purchaser not designated to purchase under subsection 3b, 3c, or 3d:

(1) The contract demand as specified in the contract;

(2) The measured demand for the billing month adjusted for power factor;

(3) The measured energy for the billing month.

b. For any purchaser designated by Bonneville to purchase on a computed demand basis because of such purchaser's potential ability either to sell generation from its resources in such a manner as to increase Bonneville's obligation to deliver firm power to such purchaser in an amount in excess of Bonneville's obligation prior to such sale, or to redistribute the generation from its resources over time in such a manner as to cause losses of power or revenue on the Federal System; provided, however, that when a purchaser operates two or more separate systems, only those systems designated by Bonneville will be covered by this subsection:

(1) The peak computed demand for the billing month;

(2) The average energy computed demand for the billing month;

(3) 60 percent of the highest peak computed demand during the previous 11 billing months;

(4) 60 percent of the highest average energy computed demand for the previous 11 billing months;

(5) The measured demand for the billing month adjusted for power factor;

(6) The measured energy for the billing month;

(7) The contract demand as specified in an agreement between a purchaser and Bonneville for a specified period of time.

c. For any purchaser contractually limited to an allocation of capacity and/or energy as determined by Bonneville pursuant to the terms of a purchaser's power sales contract:

(1) The allocated demand for the billing month, as specified in the contract;

(2) The measured demand for the billing month adjusted for power factor;

(3) The allocated energy for the billing month, as specified in the contract;

(4) The measured energy for the billing month.

d. For any purchaser participating in the exchange under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act:

(1) The scheduled demand for the billing month;

(2) The scheduled energy for the billing month.

Section 4. *Determination of Billing Demand and Billing Energy:*

a. For a purchaser governed by subsection 3a:

(1) The billing demand for the month shall be factor 3a(1) or 3a(2), as specified in the purchaser's power sales contract, except that at such time as Bonneville determines that the limitation in section 3c is necessary, the billing demand for the month shall be factor 3c(2): *Provided, however,* That billing demand factor 3c(2), before adjustment for power factor, shall not exceed factor 3c(1).

(2) The billing energy for the month shall be factor 3a(3) except that at such time as Bonneville determines that the limitation in section 3c is necessary, the billing energy shall be factor 3c(4): *Provided, however,* That factor 3c(4) shall not exceed factor 3c(3).

b. For a purchaser governed by subsection 3b:

(1) The billing demand for the month shall be the largest of factors 3b(3), 3b(4), and 3b(5), or 3b(7) if applicable. Factor 3b(5), before adjustment for power factor, shall not exceed the largest of factors 3b(1), 3b(2), or 3b(7) if applicable, except that at such time as Bonneville determines that the limitation in section 3c is necessary, the billing demand for the month shall be factor 3c(2): *Provided, however,* That billing demand factor 3c(2), before adjustment for power factor, shall not exceed factor 3c(1).

(2) The billing energy for the month shall be factor 3b(6) except that at such time as Bonneville determines that the limitation in section 3c is necessary, the billing energy shall be factor 3c(4); *Provided, however,* That factor 3c(4) shall not exceed factor 3c(3). Factor 3b(6) shall not exceed factor 3b(2) times the number of hours during such month.

c. For purchaser governed by subsection 3d:

(1) The billing demand for the month shall be factor 3d(1).

(2) The billing energy for the month shall be factor 3d(2).

Section 5. *Adjustments:*

a. *Power Factor:* The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand for each month by 1-percent for each 1-percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95-percent, such average power factor to be computed to the nearest whole percent from the formula given in section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by Bonneville. Unless specifically otherwise agreed, Bonneville may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75-percent lagging or 75-percent leading.

b. *At-Site Power:* At-site power purchased for consumption by a purchaser shall be used within 15 miles of the powerplant specified in the power sales contract. At least 90-percent of any at-site power purchased for resale shall be used within 15 miles of the specified powerplant.

The monthly demand charge for at-site firm power will be the monthly demand charge for priority firm power reduced by $0.257 per kilowatt of billing demand.

At-site priority firm power is made available only for those utility customers purchasing at-site firm power under existing contracts. At-site priority firm power may be purchased by such utility customers under new contracts only until a date certain specified in such new contracts. If deliveries are made from an interconnection with the Federal System other than at one of such designated points, the purchaser shall pay an amount adequate to cover the annual cost of the facilities which would have been required to deliver such power to such point from either the generator bus at the generating plant, or from the adjacent point as designated by Bonneville. This use-of-facilities charge shall be in addition to the charge determined by the application of section 2 of the Rate Scehdule as reduced by the provisions of this subsection.

c. *Streamflow Conditions:* Monthly energy surcharges in mills per kilowatthour will be permitted under all rate schedules for sales of firm energy if actual streamflows since the preceding July 31 plus the streamflows forecasted at the beginning of each month, January through June, for the remainder of the year through July 31 indicate less than average streamflow conditions. Bonneville shall make a compliance filing with the Federal Energy Regulatory Commission (FERC) for each month that the surcharge is applied and will provide appropriate refunds if such surcharge is reduced or disapproved by the FERC. The amount of surcharge will be limited to the lesser of:

(1) Bonneville's actual costs for purchase power in excess of the amount specified for purchase power reflected

in development of Bonneville's wholesale power rate schedules; or

(2) An amount determined by multiplying the then-current price of oil-fired thermal generation times the excess, if any, in the computed Federal Columbia River Power System (FCRPS) generation under average streamflow conditions over the computed FCRPS generation under actual plus forecasted streamflow conditions for the August 1 through July 31 period.

d. *Low-Density Discount:* A predetermined discount will be applied each month of a calendar year to the charges for power purchased under contracts to be signed between Bonneville and its customers. The amount of such discount will depend on the ratio of the total annual energy requirements of the purchaser's electric operations during the preceding calendar year to the purchaser's depreciated investment in electric plant in service (excluding generating plant) at the end of such year, or the purchaser's ratio of residential consumers per mile of line. This discount shall be:

(1) Seven percent if such ratio is less than 15 kilowatthours per dollar of net investment or if the number of consumers per mile of line is two or less.

(2) Five percent if such ratio is equal to or greater than 15 and less than 25 kilowatthours per dollar of net investment, or if the number of consumers per mile of line is four or less.

(3) Three percent if such ratio is equal to or greater than 25 and less than 35 kilowatthours per dollar of net investment, or if the number of consumers per mile of line is six or less.

Section 6. *Unauthorized Increase:* That portion of (a) any 60-minute clock-hour integrated demand or scheduled demand (the total amount of power scheduled to the purchaser from Bonneville) that cannot be assigned to a class of power which Bonneville delivers on such hour pursuant to contracts between Bonneville and the purchaser or to a type of power which the purchaser acquires from sources other than Bonneville which Bonneville delivers during such hour, or (b) the total of a purchaser's 60-minute clock-hour integrated or scheduled demands during a billing month which cannot be assigned to a class of power which Bonneville delivers during such month pursuant to contracts between Bonneville and the purchaser or to a type of power which the purchaser acquires from sources other than Bonneville which Bonneville delivers during such month, may be considered an unauthorized increase. Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to (a) and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under (b).

The charge for an unauthorized increase shall be $0.13 per kilowatthour.

Section 7. *General Provisions:* Sales of power under this Schedule shall be subject to the provisions of the Bonneville Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

Schedule IP–1—Wholesale Power Rate for Industrial Firm Power.

Section 1. *Availability:* This schedule is available for the purchase of industrial firm power and/or authorized increase on a contract demand basis and for additional power requested by the purchaser and made available as authorized increase by Bonneville on an intermittent basis. This rate schedule supersedes schedule IF–2 which went into effect on an interim basis on December 20, 1979.

Section 2. *Rate:*

a. *Demand Charge:*

1. For the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $3.10 per kilowatt of billing demand.

2. For the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $2.27 per kilowatt of billing demand.

3. All other hours: No demand charge.

b. *Energy Charge:*

1. For the billing months September through March: 5.9 mills per kilowatthour of billing energy. Effective October 1, 1981, the following charge shall be added to the energy charge of 5.9 mills per kilowatthour to cover costs incurred by the Administrator pursuant to section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act: (In mills per kilowatthour of billing energy).

$14.575\ (X) \pm 2{,}196{,}000/410{,}300$

Where X = Annual cost in thousands of dollars incurred by the Administrator pursuant to section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act.

2. For the billing months April through August: 5.4 mills per kilowatthour of billing energy. Effective October 1, 1981, the following charge shall be added to the energy of 5.4 mills per kilowatthour to cover costs incurred by the Administrator pursuant to section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act: (In mills per kilowatthour of billing energy).

$7.920\ (X) \pm 1{,}243{,}000/265{,}300$

where X = Annual cost in thousands of dollars incurred by the Administrator pursuant to section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act.

Section 3. *Billing Factors:* The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

a. Contract demand;
b. Curtailed demand;
c. Restricted demand;
d. Measured energy.

Section 4. *Determination of Billing Demand and Billing Energy:* The billing demands for industrial firm power and authorized increase, respectively, and for additional power requested by the purchaser and made available by Bonneville as authorized increase on an intermittent basis will be the lowest of the respective contract demand, curtailed demand, or restricted demand after each such demand is adjusted for power factor. The billing energy associated with each of the respective billing demands will be the measured energy distributed proportionately among the respective demands for each hour each such demand is applicable during the billing month.

Section 5. *Adjustments:*

a. *Value of Reserves:* An adjustment for the value of the reserves provided by purchasers of industrial firm power shall be:

(1) $1.18 per kilowatt of billing demand.

(2) 1.2 mills per kilowatthour of billing energy. The adjustment shall be applied to the same billing factors which are used to determine the billing for power purchased under this rate schedule.

b. *Power Factor:* The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the appropriate demand (operating, curtailed, or restricted) for each month by 1-percent for 1-percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95-percent, such average power factor to be computed to the nearest whole percent from the formula given in section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by

Bonneville. Unless specifically otherwise agreed, Bonneville may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75-percent lagging or 75-percent leading.

c. *At-Site Power:* At-site industrial firm power shall be used within 15 miles of the powerplant.

The monthly demand charge for at-site industrial firm power will be the monthly demand charge for industrial firm power reduced by $0.257 per kilowatt of billing demand.

At-site industrial firm power is made available only for those industrial customers purchasing at-site industrial firm power under existing contracts. At-site industrial firm power may be purchased by such industrial customers under new contracts only until a date certain specified in such new contracts. If deliveries are made from an interconnection with the Federal System other than at one of such designated points, the purchaser shall pay an amount adequate to cover the annual cost of the facilities which would have been required to deliver such power to such point from either the generator bus at the generating plant, or from the adjacent point as designated by Bonneville. The use of facilities charge shall be in addition to the charge determined by application of section 2 of the Rate Schedule as reduced by the provisions of this subsection.

d. *Streamflow Conditions:* Monthly energy surcharges in mills per kilowatthour will be permitted under all rate schedules for sales of firm energy if actual streamflows since the preceding July 31 plus the streamflows forecasted at the beginning of each month, January through June, for the remainder of the year through July 31 indicate less than average streamflow conditions. Bonneville shall make a compliance filing with the Federal Energy Regulatory Commission (FERC) for each month that the surcharge is applied and will provide appropriate refunds if such surcharge is reduced or disapproved by the FERC. The amount of surcharge will be limited to the lesser of:

(1) Bonneville's actual costs for purchase power in excess of the amount specified for purchase power reflected in development of Bonneville's wholesale power rate schedules; or

(2) An amount determined by multiplying the then-current price of oil-fired thermal generation times the excess, if any, in the computed Federal Columbia River Power System (FCRPS) generation under average streamflow conditions over the computed FCRPS generation under actual plus forecasted streamflow conditions for the August 1 through July 31 period.

Section 6. *Unauthorized Increase:* Any amount by which any 60-minute clock-hour integrated demand exceeds that sum of the billing demand for such hour before adjustment for power factor, plus any applicable scheduled demands which the purchaser acquires through other contracts for such hour will be assessed a charge of $0.13 per kilowatthour.

Section 7. *Special Conditions—Advance of Energy:* Bonneville may elect to advance energy under terms and conditions of the purchaser's power sale contract.

Section 8. *General Provisions:* Sales of power under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the applicable General Rate Schedule Provisions.

Schedule MP–1—Wholesale power rate for modified firm power.

Section 1. *Availability:* This schedule is available for the purchase of modified firm power on a contract basis for direct consumption by existing direct-service industrial customers until existing contracts terminate. This schedule is also available for the purchase of authorized increase power on a contract demand basis.

This rate schedule supersedes schedule MF–2 which went into effect on an interim basis on December 20, 1979.

Section 2. *Rate:*

a. *Demand Charge:*

1. For the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $3.10 per kilowatt of billing demand.

2. For the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $2.27 per kilowatt of billing demand.

3. All other hours: No demand charge.

b. *Energy Charge:*

1. For the billing months September through March: 5.9 mills per kilowatthour of billing energy. Effective October 1, 1981, the following charge shall be added to the energy charge of 5.9 mills per kilowatthour to cover costs incurred by the Administrator pursuant to section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act: (in mills per kilowatthour of billing energy).

$$14.575\ (X) - 2{,}196{,}000/410{,}300$$

where X = Annual cost in thousands of dollars incurred by the Administrator pursuant to section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act.

2. For the billing months April through August: 5.4 mills per kilowatthour of billing energy. Effective October 1, 1981, the following charge shall be added to the energy charge of 5.4 mills per kilowatthour to cover costs incurred by the Administrator pursuant to section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act: (in mills per kilowatthour of billing energy).

$$7.920\ (X) - 1{,}243{,}000/285{,}300$$

where X = Annual cost in thousands of dollars incurred by the Administrator pursuant to section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act.

Section 3. *Billing Factors:* The factors to be used in determining the billing for power purchases under this rate schedule are as follows:

a. Contract demand;

b. Curtailed demand;

c. Restricted demand;

d. Measured energy.

Section 4. *Determination of Billing Demand and Billing Energy:* The billing demand for modified firm power and authorized increase, respectively, will be the lowest of the respective contract demand, curtailed demand, or restricted demand after each such demand is adjusted for power factor. The billing energy associated with each of the respective billing demands will be the measured energy distributed proportionately among the respective demands for each hour each such demand is applicable during the billing month.

Section 5. *Adjustments:*

a. *Power Factor:* The adjustment for power factor, when specified in this rate schedule or power sales contract, may be made by increasing the appropriate demand (contract, curtailed, or restricted) for each month by 1-percent for each 1-percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95-percent, such average power factor to be computed to the nearest whole percent from the formula given in section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by Bonneville. Unless specifically otherwise agreed, Bonneville, may, if necessary to maintain acceptable operating conditions on the Federal

System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75-percent lagging or 75-percent leading.

b. *At-Site Power:* At-site modified firm power shall be used within 15 miles of the powerplant.

The monthly demand charge for at-site modified firm power will be the monthly demand charge for modified firm power reduced by $0.257 per kilowatt of billing demand.

At-site modified firm power will be made available under existing contracts, providing for at-site modified firm power at a Federal hydroelectric generating plant or at a point adjacent thereto, and at a voltage, all as designated by Bonneville. If deliveries are made from an interconnection with the Federal System other than at one of such designated points, the purchaser shall pay an amount adequate to cover the annual cost of the facilities which would have been required to deliver such power to such point from either the generator bus at the generating plant, or from the adjacent point as designated by Bonneville. This use of facilities charge shall be in addition to the charge determined by application of section 2 of the Rate Schedule as reduced by the provisions of this subsection.

c. *Streamflow Condition:* Monthly energy surcharges in mills per kilowatthour will be permitted under all rate schedules for sales of firm energy if actual streamflows since the preceding July 31 plus the streamflows forecasted at the beginning of each month, January through June, for the remainder of the year through July 31 indicate less than average streamflow conditions. Bonneville shall make a compliance filing with the Federal Energy Regulatory Commission (FERC) for each month that the surcharge is applied and will provide appropriate refunds if such surcharge is reduced or disapproved by the FERC. The amount of surcharge will be limited to the lesser of:

(1) Bonneville's actual costs for purchase power in excess of the amount specified for purchase power reflected in development of Bonneville's wholesale power rate schedules; or

(2) An amount determined by multiplying the then-current price of oil-fired thermal generation times the excess, if any, in the computed Federal Columbia River Power System (FCRPS) generation under average streamflow conditions over the computed FCRPS generation under actual plus forecasted streamflow conditions for the August 1 through July 31 period.

Section 6. *Unauthorized Increase:* Any amounts by which any 60-minute clock-hour integrated demand exceeds the sum of the billing demand for such hour (before adjustment for power factor) plus any applicable schedule demands which the purchaser acquires through other contracts for such hour will be assessed a charge of $0.13 per kilowatthour.

Section 7. *General Provisions:* Sales of power under this Schedule shall be subject to the provisions of the Bonneville Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

Schedule CF–1—Wholesale firm capacity rate.

Section 1. *Availability:* This schedule is available for the purchase of firm capacity without energy on a contract demand basis for supply during a contract year of 12 months, or during a contract season of 5 months, June 1 through October 31. This schedule supersedes schedule F–7 which went into effect on an interim basis on December 20, 1979.

Section 2. *Rate:*

a. *Contact Year Service:* $32.22 per kilowatt per year of contract demand.

b. *Contract Season Service:* $15.00 per kilowatt per season of contract demand.

c. The capacity rate specified in subsections a. and b. above shall be increased by $0.425 per kilowattmonth of billing demand for each hour that the purchaser's monthly demand duration exceeds six (6) hours. The purchaser's demand duration for the month shall be determined by dividing the kilowatthours supplied under this rate schedule to a purchaser on the day of maximum kilowatthour use between the hours of 7 a.m. and 10 p.m., excluding Sundays, by the purchaser's contract demand effective for such month. If, however, Bonneville does not require the delivery of peaking replacement energy by the purchaser during certain periods, the additional charge above will not be made for such periods.

Section 3. *Special Factors:* The billing demand will be the contract demand.

Section 4. *Special Provision:* Contracts for the purchase of firm capacity under this schedule will include provisions for replacement by the purchaser of energy accompanying the delivery of such capacity.

Section 5. *General Provisions:* Sales of power under this schedule shall be subject to the provisions of the Booneville Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the applicable General Rate Schedule Provisions.

Schedule CE–1—Emergency capacity rate.

Section 1. *Availability:* This schedule is available for purchase of emergency capacity requested by a purchaser when Bonneville determines that an emergency condition exists on the purchaser's system and it has capacity available for such purpose. This schedule supersedes schedule F-8 which went into effect on an interim basis on December 20, 1979.

Section 2. *Rate:* $0.71 per kilowatt of demand per calendar week or portion thereof. For deliveries over the Pacific Northwest-Pacific Southwest intertie, made available for the account of a purchaser at the Oregon-California or the Oregon-Nevada border, the charge will be increased by $0.20 per kilowatt per week. Bills will be rendered monthly.

Section 3. *Billing Factors:* The billing demand will be the maximum amount requested by the purchaser and made available by Bonneville during a calendar week, provided that if Bonneville is unable to meet subsequent requests by a purchaser for delivery at the demand previously established during such week, such billing demand for such week shall be the lower demand which Bonneville is able to supply.

Section 4. *Special Provision:* Energy delivered with such capacity shall be returned to Bonneville within 7 days of the date of delivery at times and rates of delivery agreed to by the purchaser and Bonneville prior to delivery. Bonneville may agree to accept delay of return energy beyond 7 days if it so agrees prior to the delivery of capacity.

Section 5. *General Provisions:* Sales of power under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

Schedule NR–1—New resource firm power rate.

Section 1. *Availability:* This schedule is available for the purchase of firm power for resale or for direct consumption by purchasers other than direct-service industrial purchasers who purchase power under rate Schedules I–1 or M–1.

Section 2. *Rate:*

a. *Demand Charge:*

(1) For the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $3.10 per kilowatt of billing demand.

(2) For the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $2.27 per kilowatt of billing demand.

(3) All other hours: No demand charge.

b. *Energy Charge:*

(1) For the billing months September through March: 21.6 mills per kilowatthour of billing energy.

(2) For the billing months April through August: 17.9 mills per kilowatthour of billing energy.

Section 3. *Billing Factors*: The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

a. For any purchaser not designated to purchase under subsection 3b or 3c:

(1) The contract demand as specified in the contract;

(2) The measured demand for the billing month adjusted for power factor;

(3) The measured energy for the billing month.

b. For any purchaser designated by Bonneville to purchase on a computed demand basis because of such purchaser's potential ability either to sell generation from its resources in such a manner as to increase Bonneville's obligation to deliver firm power to such purchaser in an amount in excess of Bonneville's obligation prior to such sale, or to redistribute the generation from its resources over time in such a manner as to cause losses of power or revenue on the Federal System; provided, however, that when a purchaser operates two or more separate systems, only those systems designated by Bonneville will be covered by this subsection:

(1) The peak computed demand for the billing month;

(2) The average energy computed demand for the billing month;

(3) 60 percent of the highest peak computed demand during the previous 11 billing months;

(4) 60 percent of the highest average energy computed demand for the previous 11 billing months;

(5) The measured demand for the billing month adjusted for power factor;

(6) The measured energy for the billing month;

(7) The contract demand as specified in an agreement between a purchaser and Bonneville for a specified period of time.

c. For any purchaser contractually limited to an allocation of capacity and/or energy as determined by Bonneville pursuant to the terms of a purchaser's power sales contract:

(1) The allocated demand for the billing month, as specified in the contract;

(2) The measured demand for the billing month adjusted for power factor;

(3) The allocated energy for the billing month, as specified in the contract;

(4) The measured energy for the billing month.

Section 4. *Determination of Billing Demand and Billing Energy:*

a. For a purchaser governed by subsection 3a:

(1) The billing demand for the month shall be factor 3a(1) or 3a(2), as specified in the purchaser's power sales contract, except that at such time as Bonneville determines that the limitation in section 3c is necessary, the billing demand for the month shall be factor 3c(2): *Provided, however,* That billing demand factor 3c(2), before adjustment for power factor, shall not exceed factor 3c(1).

(2) The billing energy for the month shall be factor 3a(3) except that at such time as Bonneville determines that the limitation in section 3c necessary, the billing energy shall be factor 3c(4), provided, however, that factor 3c(4) shall not exceed factor 3c(3).

b. For a purchaser governed by subsection 3b:

(1) The billing demand for the month shall be the largest of factors 3b(3), 3b(4), and 3b(5), or 3b(7) if applicable. Factor 3b(5), before adjustment for power factor, shall not exceed the largest of factors 3b(1), 3b(2), or 3b(7) if applicable, except that at such time as Bonneville determines that the limitation in section 3c is necessary, the billing demand for the month shall be factor 3c(2): *Provided, however,* That billing demand factor 3c(2), before adjustment for power factor, shall not exceed factor 3c(1).

(2) The billing energy for the month shall be factor 3b(6) except that at such time as Bonneville determines that the limitation in section 3c is necessary, the billing energy shall be factor 3c(4): *Provided, however,* That factor 3c(4) shall not exceed factor 3c(3). Factor 3b(6) shall not exceed factor 3b(2) times the number of hours during such month.

Section 5. *Adjustments:*

a. *Power Factor:* The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand for each month by 1-percent for each 1-percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95-percent, such average power factor to be computed to the nearest whole percent from the formula given in section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by Bonneville. Unless specifically otherwise agreed, Bonneville may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75-percent lagging or 75-percent leading.

b. *Streamflow Conditions:* Monthly energy surcharges in mills per kilowatthour will be permitted under all rate schedules for sales of firm energy if actual streamflows since the preceding July 31 plus the streamflows forecasted at the beginning of each month, January through June, for the remainder of the year through July 31 indicate less than average streamflow conditions. Bonneville shall make a compliance filing with the Federal Energy Regulatory Commission (FERC) for each month that the surcharge is applied and will provide appropriate refunds if such surcharge is reduced or disapproved by the FERC. The amount of surcharge will be limited to the lesser of:

(1) Bonneville's actual costs for purchase power in excess of the amount specified for purchase power reflected in development of Bonneville's wholesale power rate schedules; or

(2) An amount determined by multiplying the then-current price of oil-fired thermal generation times the excess, if any, in the computed Federal Columbia River Power System (FCRPS) generation under average streamflow conditions over the computed FCRPS generation under actual plus forecasted streamflow conditions for the August 1 through July 31 period.

Section 6. *Unauthorized Increase:* That portion of (a) any 60-minute clock-hour integrated demand or scheduled demand (the total amount of power scheduled to the purchaser from Bonneville) that cannot be assigned to a class of power which Bonneville delivers on such hour pursuant to contracts between Bonneville and the purchaser or to a type of power which the purchaser acquires from sources other than Bonneville which Bonneville delivers during such hour, or (b) the total of a purchaser's 60-minute clock-hour integrated or scheduled demands during a billing month which cannot be assigned to a class of power which bonneville delivers during such month

pursuant to contracts between Bonneville and the purchaser or to a type of power which the purchaser acquires from sources other than Bonneville which Bonneville delivers during such month, may be considered an unauthorized increase. Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to (a) and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under (b).

The charge for an unauthorized increase shall be $0.13 per kilowatthour.

Section 7. *General Provisions:* Sales of power under this Schedule shall be subject to the provisions of the Bonneville Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

Schedule NF–1—Wholesale nonfirm energy rate.

Section 1. *Availability:* This schedule is available for the purchase of nonfirm energy both inside and outside the Pacific Northwest. This schedule is also available for energy delivered for emergency use under the conditions set forth in section 5.1 of the General Rate Schedule Provisions. This schedule is not available for the purchase of energy which Bonneville has a firm obligation to supply. This schedule supersedes schedule H–6 which went into effect on an interim basis on December 20, 1979.

Section 2. Rate:

a. *Nonfirm Energy Rate:* The rate shall be the average cost of transmission which is 2.0 mills per kilowatthour, plus one of the following:

1. The diurnally differentiated average cost of power from hydroelectric facilities, which is 4.5 mills per kilowatthour during the period Monday through Saturday, 7 a.m. through 10 p.m.; and 3.0 mills per kilowatthour for all other hours of the year,

2. The cost of a powr purchase in mills per kilowatthour incurred since the preceding July 31, or the last time that all FCRPS reservoirs were substantially full,

3. Bonneville's cost of other resources in mills per kilowatthour operated since the preceding July 31, or the last time that all FCRPS reservoirs were substantially full, or

4. A weighted average in mills per kilowatthour based on costs from the preceding categories. As an amount of energy associated with any given power purchase or resource is used to derive a charge for a sale of an equivalent amount of nonfirm energy, that purchase or resource cost will no longer be used to determine the rate for subsequent sales.

b. Contract Rate: For contracts which refer to this schedule for determining the value of energy, the rate is 9.5 mills per kilowatthour.

Section 3. *Delivery:* Bonneville shall determine the availability of energy hereunder and the rate of delivery thereof.

Section 4. *General Provisions:* Sales of energy under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the applicable General Rate Schedule Provisions.

Schedule RP–1—Reserve power rate.

Section 1. *Availability:* This schedule is available for the purchase of:

a. Firm power to meet a purchaser's unanticipated load growth as provided in a purchaser's power sales contract;

b. Power for which Bonneville determines no other rate schedule is applicable; or

c. Power to serve a purchaser's firm power loads in circumstances where Bonneville does not have a power sales contract in force with such purchaser, and Bonneville determines that this rate should be applicable. This rate schedule supersedes schedule EC–9 which went into effect on an iterim basis on December 20, 1979.

Section 2. Rate:

a. *Demand Charge:*

(1) For the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $18.55 per kilowatt of billing demand.

(2) For the billing months June through November, Monday through Saturday, 7 a.m. throught 10 p.m.: $5.15 per kilowatt of billing demand.

(3) All other hours: No demand charge.

b. *Energy Charge:* 42.8 mills per kilowatthour of billing energy.

Section 3. *Billing Factors:* The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

a. The contract demand as specified in the contract;

b. The measured demand;

c. The contract amount of energy for the month;

d. The measured energy for the month.

Section 4. *Determination of Billing Demand and Billing Energy:* The billing demand and billing energy shall be determined as provided in a purchaser's power sales contract. If Bonneville does not have a power sales contract in force with a purchaser, the billing demand and billing energy shall be the measured demand adjusted for power factor and measured energy.

Section 5. *Unauthorized Increase.* That portion of (a) any 60-minute clock-hour integrated demand or scheduled demand (the total amount of power scheduled to the purchaser from Bonneville) that cannot be assigned to a class of power which Bonneville delivers on such hour pursuant to contracts between Bonneville and the purchaser or to a type of power which the purchaser acquires from sources other than Bonneville which Bonneville delivers during such hour, or (b) the total of a purchaser's 60-minute clock-hour integrated or scheduled demands during a billing month which cannot be assigned to a class of power which Bonneville delivers during such month pursuant to contracts between Bonneville and the purchaser or to a type of power which the purchaser acquires from sources other than Bonneville which Bonneville delivers during such month, may be considered an unauthorized increase. Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to (a) and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under (b).

The charge for an unauthorized increase shall be $0.13 per kilowatthour.

Section 6. *Adjustments.*

a. *Power Factor:* The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand for each month by 1-percent for each 1-percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95-percent, such average power factor to be computed to the nearest whole percent from the formula given in section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by Bonneville. Unless specifically

otherwise agreed, Bonneville may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75-percent lagging or 75-percent leading.

b. *Streamflow Conditions:* Monthly energy surcharges in mills per kilowatthour will be permitted under all rate schedules for sales of firm energy if actual streamflows since the preceding July 31 plus the streamflows forecasted at the beginning of each month, January through June, for the remainder of the year through July 31 indicate less than average streamflow conditions. Bonneville shall make a compliance filing with the Federal Energy Regulatory Commission (FERC) for each month that the surcharge is applied and will provide appropriate refunds if such surcharge is reduced or disapproved by the FERC. The amount of surcharge will be limited to the lesser of:

(1) Bonneville's actual costs for purchase power in excess of the amount specified for purchase power reflected in development of Bonneville's wholesale power rate schedules; or

(2) An amount determined by multiplying the then-current price of oil-fired thermal generation times the excess, if any, in the computed Federal Columbia River Power System (FCRPS) generation under average streamflow conditions over the computed FCRPS generation under actual plus forecasted streamflow conditions for the August 1 through July 31 period.

Section 7. *General Provisions:* Sales of power under this Schedule shall be subject to the provisions of the Bonneville Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

Schedule FE–1—Wholesale firm energy rate.

Section 1. *Availability:* This schedule is available for contract purchase of firm energy, to be delivered for the uses, in the amounts, and during the periods or periods specified in such contract. This schedule supersedes schedule J–2 which went into effect on an interim basis on December 20, 1979.

Section 2. *Rate:* 9.4 mills per kilowatthour of billing energy.

Section 3. *Billing Factors:* The contract energy is the billing factor.

Section 4. *Determination of Billing Energy:* The billing energy shall be determined as provided in the purchaser's power sales contract.

Section 5. *Delivery:* Delivery of energy under this rate schedule is assured during the contract period. However, Bonneville may interrupt the delivery of firm energy hereunder, in whole or in part, at any time that Bonneville determines that Bonneville is unable because of system operating conditions, including lack of generation or transmission capacity, to effect such delivery.

Section 6. *Adjustments:*

a. *Power Factor:* The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the contract energy delivered for each month by 1-percent for each 1-percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95-percent, such average power factor to be computed to the nearest whole percent from the formula given in section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by Bonneville. Unless specifically otherwise agreed, Bonneville may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to the purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75-percent lagging or 75-percent leading.

b. *Streamflow Conditions:* Monthly energy surcharges in mills per kilowatthour will be permitted under all rate schedules for sales of firm energy if actual streamflows since the preceding July 31 plus the streamflows forecasted at the beginning of each month, January through June, for the remainder for the year through July 31 indicate less than average streamflow conditions. Bonneville shall make a compliance filing with the Federal Energy Regulatory Commission (FERC) for each month that the surcharge is applied and will provide appropriate refunds if such surcharge is reduced or disapporved by the FERC. The amount of surcharge will be limited to the lesser of:

(1) Bonneville's actual costs for purchase power in excess of the amount specified for purchase power reflected in development of Bonneville's wholesale power rate schedules; or

(2) An amount determined by multiplying the then-current price of oil-fired thermal generation times the excess, if any, in the computed Federal Columbia River Power System (FCRPS) generation under average streamflow conditions over the computed FCRPS generation under actual plus forecasted streamflow conditions for the August 1 through July 31 period.

SECTION 7. *General Provisions:* Sales of power under this Schedule shall be subject to the provisions of the Bonneville Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

General Rate Schedule Provisions

SECTION 1.1 *Priority and New Resource Firm Power:* Priority and new resource firm power is electric power which Bonneville will make continuously available to a purchaser to meet its net firm load requirements within the Pacific Northwest except when restricted because the operation of generation or transmission facilities used by Bonneville to service such purchaser is suspended, interrupted, interfered with, curtailed, or restricted as the result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract. Such restriction of priority and new resource firm power shall not be made unitl industrial firm power has been restricted in accordance with section 1.4 and until modified firm power has been restricted in accordance with section 1.2.

SECTION 1.2. *Modified Firm Power:* Modified firm power is electirc power which Bonneville will make continuously available to a purchaser on a contract demand basis subject to: (a) The restriction applicable to priority and new resource firm power, and (b) the following:

When a restriction is made necessary because the operation of generation or transmission facilities used by Bonneville to serve such purchaser and one or more priority and new resource firm power purchasers, is suspended, interrupted, interfered with, curtailed, or restricted as a result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract Bonneville shall restrict such purchaser's contract demand for modified firm power to the extent necessary to prevent, if possible, or miminize restriction of any priority and new resource firm power: *provided, however,* That:

(1) Such restriction of modified firm power shall not exceed at any time 25-percent of the contract demand therefore, and

(2) The accumulation of such restrictions of modified firm power during any calendar year, expressed in Kilowatthours, shall not exceed 500 times the contract demand therefor. When possible, restrictions of modified firm power will be made ratably with restrictions of industrial firm power based on the proportion that the respective contract demands bear to one another. The extent of such restrictions shall be limited for modified firm power by this subsection and for industrial firm power by the Restriction of Deliveries Section of the General Contract Provisions of the contract.

SECTION 1.3. *Firm Capacity:* Firm capacity is capacity which Bonneville assures will be available to a purchaser on a contract demand basis except when operation of generation or transmission facilities used Bonneville to serve purchaser is suspended, interrupted, interfered with, curtailed, or restricted as the result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract.

SECTION 1.4. *Industrial Firm Power:* Industrial firm power is electric power which Bonneville will make continuously available to a purchaser on a contract demand basis subject to: (a) The restriction applicable to priority and new resource firm power, and (b) the following:

(1) The restrictions given in the Restriction of Deliveries Section of the General Contract provisions of the contract.

(2) When a restriction is made necessary because of the operation of generation or transmission facilities used by Bonneville to serve such purchaser and one or more priority and new resource firm power purchasers is suspended, interrupted, interfered with, curtailed, or restricted as a result of the occurrence of any condition described in the Uncontrollable Force or Continuity of Service Sections of the General Contract Provisions of the contract, Bonneville shall restrict such purchaser's contract demand for industrial firm power to the extent necessary to prevent, if possible, or minimize restriction of priority and new resource firm power. When possible, restrictions of industrial firm power will be made ratably with restrictions of modified firm power based on the proportion that the respective contract demands bear to one another. The extent of such restrictions shall be limited for modified firm power by section 1.2(b) of these General Rate Schedule Provisions and for industrial firm power by the Restrictions of Deliveries Section of the General Contract Provisions of the contract.

SECTION 1.5. *Authorized Increase:* An authorized increase is an amount of electric power specified in the contract in excess of the contract demand for priority firm power, new resource firm power, modified firm power, or industrial firm power that Bonneville may be able to make available to the purchaser upon its request. The purchaser shall make such request in writing stating the amount of increase requested, the purpose for which it will be used, and the period for which it is needed. Such request shall be made prior to the first calendar month beginning such specified period. Bonneville will then determine whether such increase can be made available, but it shall retain the right to restrict the delivery of such increase if it determines at any subsequent time that such increase will no longer be available.

The purchaser may curtail an authorized increase, in whole or in part, at the end of any billing month within the period such authorized increase is to be made available.

Section 1.6. *Firm Energy:* Firm energy is energy which Bonneville assures will be available to a purchaser during the period or periods specified in the contract and when the operation of the Government's facilities used to serve the purchaser are suspended, interrupted, interfered with, curtailed, or restricted by the occurrence of any condition described in the uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract.

SECTION 2.1. *Contract Demand:* The contract demand shall be the number of kilowatts that the purchaser agrees to purchase and Bonneville agrees to make available. Bonneville may agree to make deliveries at a rate in excess of the contract demand at the request of the purchaser (authorized increase), but shall not be obligated to continue such excess deliveries.

SECTION 2.2. *Measured Demand:* Except where deliveries are scheduled as hereinafter provided, the measured demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands at which electric energy is delivered to a purchaser at each point of delivery during each time peirod specified in the applicable rate schedule during any billing period. Such largest 60-minute integrated demand shall be determined in section 3.2 herein. Bonneville, in determining the measured demand, will exclude any abnormal 60-minute integrated demands due to or resulting from (a) emergencies or breakdowns on, or maintenance of, the Federal System facilities, and (b) emergencies on the purchaser's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by Bonneville. For those contracts to which Bonneville is a party and which provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute integrated demand assigned to any class of power shall be determined as specified in the contract. The portion of the total measured demand so assigned shall consitute the measured demand for each such class of power.

If the flow of electric energy to a purchaser's system through two or more points of delivery cannot be adequately controlled because such points are interconnected within the purchaser's system, or the purchaser's system is interconnected directly or indirectly with the Federal System, the purchaser's measured demand for each class of power for such system for any billing period shall be the largest of the hourly amounts of such class of power which are scheduled for delivery to the purchaser during each time period specified in the applicable rate schedule.

SECTION 2.3. *Peak Computed Demand and Energy Computed Demand:* The purchaser's peak computed demand for each billing month shall be the largest amount during such month by which the purchaser's 60-minute system demand exceeds its assured peaking capability.

The purchaser's average energy computed demand for each billing month shall be the amount during such month by which the purchaser's actual system average load exceeds its assured average energy capability.

a. *General Principles:*

(1) The assured peaking and average energy capability of each of the purchaser's systems shall be determined and applied separately.

(2) As used in this section, "year" shall mean the 12-month period commencing July 1.

(3) The critical period is that period, determined for the purchaser's system under adverse streamflow conditions adjusted for current water uses, assured storage operation, and appropriate operating agreements, during which the purchaser would have the maximum requirement for peaking or energy after utilizing the firm capability of all resources available to its system in such a manner as to place the least

requirement for capacity and energy on Bonneville.

(4) Critical water conditions are those conditions of streamflow based on historical records, adjusted for current water uses, assured storage operation, and appropriate operating agreements, for the year or years which would result in the minimum capability of the purchaser's firm resources during the critical period.

(5) Prior to the beginning of each year the purchaser shall determine the assured capability of each of the purchaser's systems in terms of peaking and average energy for each month of each year or year within the critical period. The firm capability of all resources available to the purchaser's system shall be utilized in such a manner as to place the least requirement for capacity and energy on Bonneville. Such assured capability shall be effective after review and approval by Bonneville.

(6) The purchaser's assured energy capability shall be determined by shaping its firm resources to its firm load in a manner which places a uniform requirement on Bonneville within each year of the critical period with such requirement increasing each year not in excess of the purchaser's annual load growth.

(7) As used herein, the capability of a firm resource shall include only that portion of the total capability of such resource which the purchaser can deliver on a firm basis to its load. The capabilities of all generating facilities which are claimed as part of the purchaser's assured capability shall be determined by test or other substantiating data acceptable to Bonneville. Bonneville may require verification of the capabilities of any or all of the purchaser's generating facilities. Such verification will not be required more often than once each year for operating plants, or more often than once each third year for thermal plants in cold standby status, if Bonneville determines that adequate annual preventive maintenance is performed and the plant is capable of operating at its claimed capability.

(8) In determining assured capability, the aggregate capability of the purchaser's firm resources shall be appropriately reduced to provide adequate reserves.

b. *Determination of Assured Capability:* The purchaser's assured peaking and energy capabilities shall be the respective sums of the capabilities of its hydroelectric generating plants based on the most critical water conditions on the purchaser's system, the capabilities of its thermal generating plants based on the adverse fuel or other conditions reasonably to be anticipated; and the firm capabilities of other resources made available under contracts prior to the beginning of the year, after deduction of adequate reserves. Assured capabilities shall be determined for each month if the purchaser has seasonal storage. The capabilities of the purchaser's firm resources shall be determined as follows:

(1) *Hydroelectric Generating Facilities:* The capability of each of the purchaser's hydroelectric generating plants shall be determined in terms of both peaking and average energy using critical water conditions. The average energy capability shall be that capability which would be available under the storage operation necessary to produce the claimed peaking capability.

Seasonal storage shall mean storage sufficient to regulate all the purchaser's hydroelectric resources in such a manner that when combined with the purchaser's thermal generating facilities, if any, and with firm capacity and energy available to the purchaser under contracts, a uniform energy computed demand for a period of one (1) month or more would result.

A purchaser having seasonal storage shall, within 10 days after the end of each month in the critical period, notify Bonneville in writing of the assured energy capability to be applied tentatively to the preceding month; such notice shall also specify the purchaser's best estimate of its average system energy load for such month. If such notice is not submitted, or is submitted later than 10 days after the end of the month to which it applies, subject to the limitations stated herein, the assured energy capability determined for such month prior to the beginning of the year shall be applied to such month and may not be changed thereafter.

If notice has been submitted pursuant to the preceding paragraph, the purchaser shall, within 30 days after the end of the month, submit final specification of the assured energy capability to be applied to the preceding month: *Provided,* That the assured energy capability so specified shall not differ from the amount shown in the original notice by more than the amount by which the purchaser's actual average system energy load for such month differs from the estimate of that load shown in the original notice. If the assured energy capability for such month differs from that determined prior to the beginning of the year for such month, the purchaser, if required by Bonneville, shall demonstrate by a suitable regulation study based on critical water conditions that such change could actually be accomplished, and that the remaining balance of its total critical period assured energy capability could be developed without adversely affecting the firm capability of other purchaser's resources. The algebraic sum of all such changes in the purchaser's assured energy capability shall be zero at the end of the critical period or year, whichever is earlier. Appropriate adjustments in the assured peaking capability shall be made if required by any change in reservoir operation indicated by such revisions in the monthly distribution of critical period energy capability.

(2) *Thermal Generating Facilities:* The capability of each of the purchaser's thermal generating plants shall be determined in terms of both peaking and average energy. Such capabilities shall be based on the adverse fuel or other conditions reasonably to be anticipated. The effect of limitations on fuel supply due to war or other extraordinary situations will be evaluated at the time of occurrence.

(3) *Other Sources of Power:* The assured capability of other resources available to the purchaser on a firm basis under contracts shall be determined prior to each year in terms of both peaking and average energy.

c. *Determination of Computed Demand:* The purchaser's computed demand for each billing month shall be the greater of:

(1) The largest amount during such month by which the purchaser's actual 60-minute system demand, excluding any loads otherwise provided for in the contract, exceeds its assured peaking capability for such month, or period within such month, or

(2) The largest amount for such month, or period within such month, by which the purchaser's actual system average energy load, excluding the average energy loads otherwise provided for in the contract, exceeds its assured average energy capability.

The use of computed demands as one of the alternatives in determining billing demand is intended to assure that each purchaser who purchases power from Bonneville to supplement its own firm resources will purchase amounts of power substantially equivalent to the additional capacity and energy which the purchaser would otherwise have to provide on the basis of normal and prudent operations, viz, sufficient capacity and energy to carry the load through the most critical water or other conditions reasonably to be anticipated, with an adequate reserve.

Since the computed demand depends on the relationship of capability of resources to system requirements, the

computed demand for any month cannot be determined until after the end of the month. As each purchaser must estimate its own load, and is in the best position to follow its development from day to day, it will be the purchaser's responsibility to request scheduling of priority and new resource firm power, including any increase over previously established demands, on the basis estimated by the purchaser to result in the most advantageous purchase of the power to be billed at the end of the month.

Each contract in which computed demand may be a factor in determining the billing demand shall have attached to it as an exhibit a sample calculation of the computed demand of the purchaser for the period having the highest computed demand during the 12 months immediately preceding the effective date of the contract.

SECTION 2.4. *Restricted Demand:* A restricted demand shall be the number of kilowatts of priority firm power, new resource firm power, modified firm power, industrial firm power, or authorized increase of any of the preceding classes of power which results when Bonneville has restricted delivery of such power for one (1) clock-hour or more. Such restrictions by Bonneville are made pursuant to section 8 of the General Contract Provisions for industrial firm power and pursuant to section 1.1 and 1.2 of the General Rate Schedule Provisions for priority and new resource firm power and modified firm power, respectively. Such restricted demand shall be determined by Bonneville after the purchaser has made its determination to accept such restriction or to curtail its contract demand for the month in accordance with section 2.5 of the General Rate Schedule Provisions.

SECTION 2.5. *Curtailed Demand:* A curtailed demand shall be the number of kilowatts of priority firm power, new resource firm power, modified firm power, industrial firm power, or authorized increase of any of the preceding classes of power which results from the purchaser's request for such power in amounts less than the contract demand therefor. Each purchaser of industrial firm power or modified firm power may curtail its demand in accordance with the section entitled "Curtailment of Deliveries and Payment Therefor" of the General Contract Provisions of the contract. Each purchaser of an authorized increase in excess of priority firm power, new resource firm power, modified firm power, or industrial firm power may curtail its demand in accordance with section 1.5 of the General Rate Schedule Provisions.

SECTION 3.1. *Billing:* Unless otherwise provided in the contract, power made available to a purchaser at more than one point of delivery shall be billed separately under the applicable rate schedule or schedules. The contract may provide for combined billing under specified conditions and terms when (a) delivery at more than one point is beneficial to Bonneville, or (b) the flow of power at the several points of delivery is reasonably beyond the control of the purchaser.

If deliveries at more than one point of delivery are billed on a combined basis for the convenience of the customer, a charge will be made for the diversity between the measured demands at the several points of delivery. The charge for the diversity shall be determined in a uniform manner among purchasers and shall be specified in the contract.

SECTION 3.2. *Determination of Estimated Billing Data:* If the purchased amounts of capacity, energy, or the 60-minute integrated demands for energy must be estimated from data other than metered or scheduled quantities, Bonneville and the purchaser will agree on billing data to be used in preparing the bill. If the parties cannot agree on estimated billing quantities, a determination binding on both parties shall be made in accordance with the arbitration provisions of the contract.

SECTION 4.1. *Application of Rates During Initial Operation Period:* For an initial operating period, not in excess of 3 months, beginning with the commencement of operation of new industrial plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, Bonneville may agree (a) to bill for service to such new, additional, or reactivated plant facilities on the basis of the measured demand for each day, adjusted for power factor, or (b) if such facilities are served by a distributor purchasing power therefor from Bonneville to bill for that portion of such distributor's load which results from service to such facilities on the basis of the measured demand for each day, adjusted for power factor. Any rate schedule provisions regarding contract demand, billing demand, and minimum monthly charge which are inconsistent with this section shall be inoperative during such initial operating period.

The initial operating period and the special billing provisions may, on approval by Bonneville, be extended beyond the initial 3 month period for such additional time as is justified by the developmental character of the operations.

SECTION 5.1. *Energy Supplies for Emergency Use:* A purchaser taking priority and/or new resource firm power shall pay in accordance with Wholesale Nonfirm Energy Rate Schedule NF–1 and Emergency Capacity Schedule CE–1 for any electric energy which has been supplied (a) for use during an emergency on the purchaser's system, or (b) following an emergency to replace energy secured from sources other than Bonneville during such emergency, except that mutual emergency assistance may be provided and settled under exchange agreements.

SECTION 6.1. *Billing Month:* Meters will normally be read and bills computed at intervals of 1 month. A month is defined as the interval between meter-reading dates which normally will be approximately 30 days. If service is for less or more than the normal billing month, the monthly charges stated in the applicable rate schedule will be appropriately adjusted. Winter and summer periods identified in the rate schedules will begin and end with the beginning and ending of the purchaser's billing month having meter-reading dates closest to the period so identified.

SECTION 7.1. *Payment of Bills:* Bills for power shall be rendered monthly and shall be payable at Bonneville's headquarters. Failure to receive a bill shall not release the purchaser from liability for payment. Demand and energy billings under each rate schedule application shall be rounded to whole dollar amounts, by elimination of any amount of less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

If Bonneville is unable to render the purchaser a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill, if so issued, shall have the validity of and be subject to the same repayment provisions as shall a final bill.

Bills not paid in full on or before the close of business of the 20th day after the date of the bill shall bear an additional charge which shall be the greater of one-fourth percent (0.25%) of the amount unpaid or $50. Thereafter a charge on one-twentieth percent (0.05%) of the sum of the initial amount remaining unpaid and the additional charge herein described shall be added on each succeeding day until the amount due is paid in full. The provisions of this paragraph shall not apply to bills rendered under contracts with other agencies of the United States.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the 20th day after the date of the bill. If the 20th day after the date of the bill is a Sunday or other nonbusiness day of the purchaser, the next following business day shall be the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the 20th day must bear a postal department cancellation in order to avoid assessment of such further charges.

Bonneville may, whenever a power bill or a portion thereof remains unpaid subsequent to the 20th day after the date of the bill, and after giving 30 days advance notice in writing, cancel the contract for service to the purchaser, but such cancellation shall not affect the purchaser's liability for any charges accrued prior thereto.

SECTION 8.1. *Approval of Rates:* Schedules of rates and charges, or modifications thereof, for electric power sold by Bonneville shall become effective on a final basis after confirmation and approval by the Federal Energy Regulatory Commission. Pending the establishment of procedures by the Commission to approve rates on a final basis, the entity or entities having been designated by the Secretary of Energy prior to December 5, 1980, shall have authority to confirm and approve schedules of rates and charges on an interim basis.

SECTION 9.1. *Average Power Factor:* The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{\sqrt{(\text{Kilowatthours})^2 + (\text{Reactive Kilovoltamperehours})^2}}$$

The data used in the above formula shall be obtained from meters which are ratcheted to prevent reverse registration.

When deliveries to a purchaser at any point of delivery include more than one class of power or are under more than one rate schedule, and it is impracticable to separately meter the kilowatthours and reactive kilovoltamperehours for each class, the average power factor of the total deliveries for the month will be used, where applicable, as the power factor for each of the separate classes of power and rate schedules.

SECTION 10.1. *Temporary Curtailment of Contract Demand*: The reduction of charges for power curtailed pursuant to the purchaser's contract and section 1.5 and 2.5 hereof shall be applied in a uniform manner.

SECTION 11.1. *General Provisions*: The Wholesale Rate Schedules and General Rate Schedule Provisions of the Bonneville Power Administration effective July 1, 1981, supersede in their entirety Bonneville's Wholesale Power Rate Schedule Provisions effective December 20, 1979.

IV. *MAJOR ISSUES*: The rate schedules included in this Notice comprise Bonneville's initial proposal for wholesale power rates. After the hearing process, the Administrator will develop final rates which, upon approval, will become effective July 1, 1981.

Bonneville has conducted many studies in preparation of the proposal. They include a repayment study to determine revenue requirements, a fully allocated cost of service analysis, a long-run incremental cost of service study, a time differentiated pricing analysis, an analysis of the value of reserves, and a set of rate design studies developed to examine alternate rate structures and rate levels. The cost of service studies and repayment study were developed as the foundation for the rate schedules.

The alternatives considered in developing the rate proposals and the important issues raised by the proposal are summarized under two headings: Major Studies and Wholesale Power Rates.

A. *Major Studies.*

1. *Repayment Study*: Bonneville's statutory obligation is to set rates at a level sufficient to produce revenues that will recover all operating costs and, in addition, repay the Government investment in power facilities within a reasonable period of time, commonly interpreted as 50 years from the date a facility is placed in service or the average service life of the facilities, whichever is less. Bonneville uses a repayment period of 50 years for hydroelectric generating facilities and 35 years for transmission facilities. In addition, power revenues must repay that portion of the construction costs of Federal irrigation projects which is beyond the repaymnent ability of irrigators.

The FCRPS revenue requirement has traditionally been determined through the preparation of a repayment study which calculates the minimum level of revenue required to meet Bonneville's statutory obligation to recover all FCRPS costs, which include purchased power, operation and maintenance, interest, and amortization of the investment in power facilities within the repayment periods. The test of sufficiency of revenues is recovery of costs within the repayment period.

Bonneville performed a repayment study in September 1980 which indicated the need for an increase in revenues derived from both wholesale power rates and transmission rates. The assumptions used in the study are detailed in the Cost of Service Analysis (COSA).

The passage of the Act on December 5, 1980, has necessitated an abbreviated approach to determine Bonneville's revenue requirement for this initial proposal. If sufficient time had been available, Bonneville would have revised its repayment model to reflect Bonneville's new obligations under the Act and to directly determine the revenue requirements. Instead, all additional required costs due to the Act have been estimated and included directly in the COSA. The additional costs included are for the Pacific Northwest Electric Power and Conservation Planning Council, fish and wildlife, local government assistance, load requirements and forecasting, public involvement, system planning, contracts, rates, energy conservation, billing credits, additional short term power purchases, nonmajor renewable resources, and new major resources. The repayment study used to develop the final rate proposal will include all appropriate costs.

2. *Cost of Service Analysis (COSA):* The form and magnitude of the proposed initial schedules are strongly influenced by results of the COSA. The COSA is based on generally accepted electric utility industry practice and procedures for this type of analysis, although modifications were made to reflect the repayment method used by Federal power marketing agencies to determine revenue requirements.

The COSA, together with certain adjustment detailed in the Summary

Rate Design Study, is designed to determine the cost of providing service to various classes of service and is used as a basis for evaluating the adequacy of various wholesale power rates and wheeling rates currently in effect.

The COSA procedure begins by selecting a future test year and determining the investment and operating expenses involved in providing service in that year. Fiscal year (FY) 1982 is used as the test year for the proposed rates because it most closely matches the period during which the rates will be in effect.

a. *Functionalization.* The first step of the cost analysis is to identify investment costs and annual costs according to functions performed by the power system. These functions are defined as generation, transmission, and metering and billling. All costs are assigned to one of these functions.

A direction of effort study is prepared to determine how certain facilities and operating expenses should be functionalized. Managers in each Bonneville subdivision identified both the precentage of staff effort expended on each of the three functions and functional use of facilities. The application of the results of the direction of effort study to the test year cost estimates yields functionalized cost data.

b. *Classification.* The cost functionalized to generation are then clasified to the two subfunctions of generation capacity and energy production. The classification of generation costs is based on the principle of cost causation. This method apportions generation costs between capacity and energy in relation to the causes underlying the construction and operation of various generating plants; i.e., the cost of facilities constructed to meet peaking capacity is classified entirely to capacity and the cost of facilities which provide both capacity and energy is apportioned between the two functions.

Bonneville examined many different classification methods. The traditional method is to classify all costs associated with investment to capacity and all costs associated with plant operation to energy. This method is called the fixed-variable classification approach. In the short run, all the costs which do not vary with output are fixed costs and all costs which vary with output are variable costs. This approach may be appropriate for a system which is primarily thermal, or for system with a large thermal base and hydro peaking facilities. However, Bonneville rejected the fixed-variable approach because it did not reflect the capacity and energy relationship which was developed during the planning of a hydro system such as the FCRPS.

Based on knowledge of how the Federal system costs have been and are being incurred, Bonneville staff recommends a classification method for hydroelectric facilities that involved separating costs of plants defined as baseload from costs of peaking units. These peaking units would not have been needed had capacity requriements not increased, since they produce no incremental energy under critical water conditions. Consequently, the costs of the peaking units which include perviously constructed substructures are classified to capacity because providing capacity was the primary purpose of installing these units.

Classification of the base hydroelectirc plants is a function of the energy produced by the base system under critical streamflow conditions and the peaking capacity of these units based on a sustained 10-hour peak period. Base system plant costs for FY 82 as well as associated operation and maintenance costs are classifed 27 percent to energy and 73 percent to capacity.

Bonneville's classifiction method for all other generation resources recognizes that they are being acquired primarily to provide baseload energy, although Bonneville recognizes that most resources also provide capacity. The classification percentages applied to other generation resources are derived in Bonneville's long run incremental cost analysis. This approach results in classification of 27 percent of plant costs to capacity and 73 percent to energy. All fuel and variable operation and maintenance expenses are classified to energy. The same classification procedure has been applied to both the cost of nonmajor renewable and new major resources acquired under the Act. In addition, short term power purchases, conservation and billing credits are classified to energy, and other Act related costs are classified to capacity.

Transmission costs are commonly classified using the fixed-variable method. This method classifies all transmission costs to capacity based on the view that peak usage, not variable energy usage, is determinative of the necessary plant investment. Bonneville has considered utilizing the cost causation approach to the classification of transmission costs. This would result in some costs being classified to energy because certain investment decisions, principally those costs associated with conductor sizing and towers, are influenced by the desire to reduce energy losses and are affected by the expected volume of energy deliveries. Preliminary staff analysis indicates that some portion of the transmission system costs are related to energy deliveries. However, an acceptable alternative methodology for the classification of a portion of transmission costs to energy has not been developed. Therefore, the traditional fixed-variable method of classifying transmission costs entirely to capacity is adopted for this COSA. Bonneville invites suggestions for other methodologies for classifying transmission costs.

c. *Segmentation.* Although Bonneville operates a regionwide transmission system, some segments of the system are not needed to provide some services. To assure an equitable allocation of the costs of the system among all classes of service, the system has been divided into seven segments so that the costs of each segment can be separtely identified and allocated in relation to the service being provided. The seven transmission segments are: Intergrated network, Pacific Northwest-Southwest intertie, generation intergration, fringe area facilities, preference customer delivery facilities, DSI customer delivery facilities, and IOU delivery facilities.

d. *Allocation.* The final major step in the COSA is to allocate the functionalized and classified costs to service classes. The service classes included are wholesale power rates, transmission rates, other service, and miscellaneous service and revenues. The wholesale power rates cataegory is further divided into subcategories. They are Priority Firm, Industrial Firm, Firm Capacity, New Resources Firm, and Nonfirm Energy.

Priority Firm and new Resources Firm are new subcategories for wholesale power rates. Priority Firm consists of public body, cooperative and Federal agency customers within the region and the residential and small farm load of the region's utilities participating in the exchange. In the past this subcategory hab been referred to as Firm Power and it did not include load associated with utilities participating in the exchange. The New Resource Firm consists of load as per section 7(f) of the Act. Transmission costs have been allocated to these new loads.

The method adopted for allocating generation capacity costs and the costs associated with the seven segments of the transmission system is the average of the 12 monthly coincidental peak demands (12 CP). Because the power system is designed to provide capacity to meet coincidental peak demands over the full course of the operating year, this

method reflects the contribution of each customer class in relation to the need for total system capacity. When it is not feasible to develop allocation factors, costs are assigned using the revenue credit method. The amount of costs assigned is equal to the revenue derived from the existing charges. Costs classified to energy were allocated among the classes of service based on the kilowatthours of energy associated with each class.

3. *Long-Run Incremental Cost Analysis (LRIC):* A LRIC study was conducted by Bonneville to indicate the incremental costs Bonneville is incurring for new generation and transmission. The LRIC study provides a basis for developing rates from an economic efficiency criterion. Considerable disagreement exists about how the concept should be used in establishing rates. At issue are questions relating to measurement of marginal costs, application of marginal costs to rates, and the adjustment of such rates to the revenue requirement. All of these issues have been considered in development of Bonneville's LRIC study.

This analysis was completed prior to the passage of the Act and has not been revised. It is not expected that revisions due to the Act will significantly affect the results of the analysis.

The first step of the LRIC analysis consisted of determining how the system would react to changes in loads, and then collecting the necessary data to measure the corresponding effect on total cost in the resulting long run incremental cost. This process involved analysis of expected additional demands upon Bonneville's system and plans for additional generation plant and transmission facilities to meet these demands.

The LRIC of generation is divided between capacity costs and energy costs. The LRIC of capacity is based on additional resources added to the system to meet peaking requirements. Bonneville's peaking requirements will be met by additions of peaking units at existing hydro plants. Annual investment costs, annual operation and maintenance expenses, and annual replacement costs (all expressed in 1982 dollars) divided by the nameplate capacity, adjusted for a reserve factor, produces a dollars per kilowatt LRIC of capacity. The long run incremental cost of capacity for Bonneville is $80.41 per kilowatt of capacity.

The long run incremental cost of producing energy is based on the cost of baseload thermal power with an adjustment for a capacity credit. For the analysis, Bonneville assumed the technologies associated with the Washington Public Power Supply System plants Nos. 1, 2, and 3 as typical of baseload power plant costs. Based on these plants the weighted average LRIC of energy is 42.76 mills per kilowatthour.

The LRIC of transmission is based on transmission investment through 1989 plus annual operation and maintenance expenses associated with new transmission facilities. The incremental annual cost per kilowatt of added peak for the period 1981–1989 is $61.81 to meet transmission reinforcement requirements.

4. *Time Differentiated Pricing Analysis (TDPA):* As part of the process for development of proposed rates, a separate study on time differentiation is prepared. Time differentiated pricing is a rate design concept which has evolved because demand for electricity varies over the day and over the year. To the extent that rates of electricity consumption over different time periods result in differences in cost, time differentiated pricing deals with the problem by addressing these variations within the framework of a pricing structure.

This analysis was completed prior to the passage of the Act and has not been revised. It is not expected that revisions due to the Act will significantly affect the results of the analysis.

Time differentiated pricing is based on the concept of cost causation. In the short run, demand for power must be met from existing capacity if it is available. In the long run, the variable nature of consumption over different time periods may require additional capacity to meet peak load demands. Because additional capacity and energy are required during peak periods, the cost of supplying that energy and capacity may be higher during peak periods.

Bonneville's TDPA considers time differentiation for both average costs and incremental costs. An attempt is made to incorporate the best available data and reasonable methods given Bonneville's physical, operational, and financial system. The general method for determining Bonneville's time differentiated average costs of capacity relies on a procedure developed by Ebasco Services, Inc. The procedure for time differentiated incremental costs relies on a method developed by National Economic Research Associates.

An analysis of Bonneville's loads for the FYs 1975–1979, FCRPS generation data, and probability of negative margin (PONM) data indicate that the winter peak period for generation capacity from both an LRIC and an average cost perspective should be defined as December through May, Monday through Friday, 7 a.m. to 10 p.m. The summer season peak period is indicated to be June through November, Monday through Friday, 7 a.m. to 10 p.m. The offpeak capacity hours are all other hours of the year.

Transmission systems are designed and built to satisfy system peak loads with consideration given to ambient temperature change. Ambient temperature directly affects transmission cable resistance such that system load carrying capabilities are above average in the winter and less than average in the summer. These changes roughly offset seasonal variations in loads but amplify diurnal load variations which suggests that transmission capacity costs should be diurnally but not seasonally time differentiated. An analysis of FY 75 through FY 79 data has determined that the peak period for transmission costs should be Monday through Friday, 7 a.m. to 10 p.m. and the offpeak period should be all other hours of the year.

For most electric utilities, energy costs will vary over the day and year as fuel costs vary by time period. However, the FCRPS is unlike most other electric systems because of the large portion of hydroelectric power in the system and the absence of thermal peaking units. For a system with thermal peaking units there is a significant difference in energy costs between the peak and offpeak periods. For the Federal system, thermal plants are considered baseload and are designed to operate throughout the year except for planned maintenance, refueling, and forced outages. These outages are dependent upon many factors including fuel life, equipment failure, demand for energy, and the availability of alternative resources and thus, may occur throughout the year. These resources have been added to the Federal system to supply needed energy on an annual basis under critical water conditions, Bonneville's planning criterion. From a planning perspective, increases in demand for energy at any hour of the year require baseload thermal additions. Therefore, the cost of providing energy from baseload thermal plants is the same for each hour of the year, regardless of operating characteristics. Thus, from an incremental cost perspective, there should not be any time differentiation of energy costs.

The remaining resources are hydroelectric, which do not involve costs which vary by time period, except for costs associated with the storage of water to meet winter peak season energy requirements. Consequently,

from an average cost perspective, energy costs vary seasonally, but not diurnally. The two seasonal energy periods are April through August and September through March.

After selecting the seasonal costing/pricing periods, the cost allocation factors were developed. For long run incremental capacity costs, the pertinent relative PONM in each period is used to allocate system capacity costs among periods. The PONM data indicate that all capacity costs should be assigned to December through May, Monday through Friday, 7 a.m. to 10 p.m. The LRIC transmission costs are assigned to the peak period of Monday through Friday, 7 a.m. to 10 p.m. for all months of the year.

Generation costs for FY 1982 from the cost of service analysis are assigned to each period using an analysis of load duration curves of Federal firm loads for FYs 1975–1979. Of the total capacity costs required, 39.2 percent is apportioned to the winter season peak hours, 21.4 percent to the summer season peak hours, and 39.4 percent to the offpeak period.

Transmission costs for FY 82 from COSA are assigned to each period based on the assignment of generation capacity costs. Of the total capacity costs, 60.6 percent is apportioned to the peak hours and 39.4 percent to the offpeak hours.

Energy costs for FY 1982 are assigned to each energy period using an analysis of projected energy load generation from reservoir storage.

B. *Wholesale Power Rates.* There are several issues related to each of the rate schedules. Each issue is discussed separately by rate schedule. Issues which relate to all of the rates are discussed under a separate heading.

1. *Wholesale Priority Firm Power Rate PF–1:* Schedule PF–1 is available to meet loads of public body, cooperative, and Federal agency customers within the region and the residential and small farm loads of the region's utilities participating in the exchange. Public body, cooperative, and Federal agency customers are presently being served under the EC–8 firm power rate.

All loads served by the priority firm rate are served out of Federal base system resources. Several adjustments are made to COSA results which indicated the total cost allocated to Federal base system. The net effect of these adjustments are directly reflected in the PF–1 schedule.

The proposed NE–1 nonfirm energy rate produces revenues in excess of allocated costs that amount to $136.7 million. The proposed ET transmission rate schedule, which is part of the initial transmission rate filing, produces revenue in excess of costs that amount to $11.3 million. Excess revenues are applied as a credit to total capacity costs with $109.6 million credited to generation capacity costs and $31.0 million credited against the transmission costs allocated to the wholesale power rates. The remaining excess revenues are credited against the proposed transmission rates. The derivation of these estimates is included in the Summary Rate Design Study. In Bonneville's last wholesale power rate filing, all excess revenues from nonfirm energy sales were credited only to generation.

The primary reason for applying the credit to capacity costs is to reflect the incremental cost relationship between capacity and energy which is developed in the LRIC study. By comparing the results of the COSA with those of the LRIC study, it becomes evident that the costs of supplying energy are increasing at a faster rate than the costs of supplying capacity. Use of the nonfirm energy revenues to decrease the revenue requirement associated with capacity incorporates a price signal that energy costs are increasing more rapidly than capacity costs.

Time differentiation of long run incremental costs in the TDPA indicates that no generation capacity costs are incurred in the summer or offpeak periods and no transmission costs are incurred in the offpeak period. To more closely reflect these results in the rates, while also according recognition of the results of the TDPA of average costs, generation capacity costs and transmission costs are allocated only to the winter peak hours and summer peak hours. By not allocating capacity costs to the offpeak period, price signals based on long run incremental costs are strengthened. Consequently, the demand charge is time differentiated on both a daily and seasonal basis. The peak season demand charge is in effect from December through May, Monday through Saturday, 7 a.m. to 10 p.m. The summer season demand charge is in effect from June through November, Monday through Saturday, 7 a.m. to 10 p.m. There is no demand charge for deliveries on offpeak hours, which are all other hours of the year. The energy charge is seasonally differentiated based on the cost differential associated with seasonal hydro storage. Saturday is included in the peak periods for capacity charges despite the fact that the time differentiated pricing analysis indicates that it should be considered offpeak. Saturday is included as a peak day to be consistent with existing contracts that define heavy load hours as including Saturday hours of 7 a.m. to 10 p.m. and to provide for rate continuity with existing rates.

A low density discount, in accordance with section 7(d) of the Act, has been included in the PF–1 rate. The proposed discount will be applied each month of the calendar year to the charges for the power purchased under contracts to be signed between Bonneville and its customers. The amount of such discount will depend on the ratio of the total annual energy requirements of the purchaser's electric operations during the preceding calendar year to the purchaser's depreciated investment in electric plant in service (excluding generating plant) at the end of such year, or the purchaser's ratio of residential customers per mile of line. Bonneville is soliciting comments from the public pertaining to the low density discount.

2. *Wholesale Power Rate for Industrial Firm Power IP–1:* Many elements factor into the development of the industrial firm power rate. A portion of the power needed by the DSIs will be provided by Federal base system resources. The remainder will be provided by exchange resources from participating utilities. Consequently, the rate is based on costs from the two resource pools.

The IP–1 rate will be different for the period July 1, 1981 through September 30, 1981, from what it will be during the remainder of the period because the provisions the Act providing for exchange of power between Bonneville and utilities will not become effective until October 1, 1981. This interval will result in a period of 3 months during which the DSIs will purchase power at a rate which is equivalent to the priority firm rate except for adjustments to reflect the value of the reserves. Beginning October 1, 1981, the IP–1 energy rate will include an additional charge above the base rate. The formula in the IP–1 rate schedule is designed to recover from the DSIs the cost of the exchange of resources between Bonneville and participating utilities. Schedule IP–1 has been time differentiated similarly to that of schedule PF–1.

Bonneville is provided with reserves through the interruptible provisions contained in contracts with the DSI customers. In general, Bonneville can interrupt the top quartile of the industrial load at any time for any reason for service of the Administrator's other firm loads. Another 25 percent can be interrupted to offset loss of power due to delays in construction or the inability to operate new generating

projects. Additional restrictions can be made for forced outages and to maintain system reliability.

To determine the value of reserves, Bonneville categorized the reserves into three types: operating reserves, planning reserves, and stability reserves. Operating reserves are provided by the top quartile of the DSI load. Based upon the estimated cost of short term power purchases and the expected frequency of restriction in 1982, these reserves are valued at $2 million.

Planning reserves are provided by second quartile restrictions for plant delay and forced outages. Both capacity and energy reserves are provided. The third quartile of load also provides planning reserves as it is subject to interruption for forced outages. Planning reserves are estimated at 887 megawatts for energy and 1224 megawatts for capacity. Using the results detailed in the LRIC Analysis, the value of the capacity reserves is $143 million and the value of energy reserves is $332 million.

Bonneville's right to use automatic load tripping equipment and other schemes to disconnect the DSIs provides stability reserves. Stability reserves are valued at $2 million, which is the same level as operating reserves. Bonneville's analysis of the value of these reserves appears as an appendix in the Summary Rate Design Study.

Though these reserves are valued at Bonneville's incremental costs it would be inappropriate to provide the industrial customers with credit of that magnitude. Bonneville's customers are charged for power at average costs rather than marginal costs. For this reason the rate adjustment for reserves is equal to the ratio of average to marginal costs times the total value of reserves. This results in a rate adjustment of $86 million for the direct service industrial customers.

The adjustment in the proposed IP–1 rate schedule for the value of reserves is in the form of a uniform reduction in the monthly demand and energy charges. The existing rate for industrial firm power contains a formula for calculating the annual amount of credit to be given based on the annual availability of service to the DSIs.

3. *Wholesale Power Rate for Modified Firm Power MP–1:* Features of this rate schedule are similar to those associated with the IP–1 schedule including the additional charge on October 1, 1981, to recover the cost of the exchange of resources between Bonneville and participating utilities. An adjustment for value of reserves is not made under this rate schedule because Bonneville has less right to restrict the DSI load under the Modified Firm contracts than under the existing interim agreement or under the new proposed 20 year contracts.

4. *Wholesale Firm Capacity Rate CF–1:* This schedule includes a base charge which reflects the approximate cost of providing a given amount of Federal capacity for 6 hours per day and a variable charge for capacity usage in excess of 6 hours per day. The variable charge is established at a value between costs of providing service and the value of such service based on alternative costs.

The CF–1 rate schedule applies to capacity sales to utilities on a contract year and/or seasonal basis. Energy associated with the delivery of capacity is returned to Bonneville. To encourage capacity purchasers to limit their usage of Federal generating facilities, the capacity rate schedule includes the provision for an additional monthly charge if capacity usage exceeds 6 hours per day. The rationale for this additional charge is that the Federal hydro peaking system cannot produce as much capacity during daily sustained hourly periods as it can for shorter periods. When the FCRPS provides capacity for extended periods, its ability to meet firm commitments is reduced. Moreover, the return of an inordinate amount of energy during offpeak hours has the potential to place the Federal system in a spill condition and thereby reduce the economic utilization of the FCRPS hydro resources.

Development of this added charge for sustained peaking, which is in part a thermal generation load factoring service, was based on a share-the-savings principle applied to an estimate of the fuel savings realized by the customer by not having to operate a peaking plant. An estimated annual turbine fuel cost in FY 1982 of 51 mills per kilowatthour is reduced by 17 mills per kilowatthour to net the estimated operating cost of low cost thermal plants which would be used to return energy during the offpeak period. The resulting net fuel cost (or net savings) of 34 mills per kilowatthour is then reduced by one-half to arrive at 17 mills per kilowatthour. Application of this savings to 1 hour each day for 25 peak days per month yields a charge of $0.425 per kilowattmonth for each additional hour of capacity in excess of 6 hours, applied to all capacity taken during the given month. Bonneville reviews the daily deliveries of capacity which have been sold during the peak hours 7 a.m. through 10 p.m. excluding Sundays under this rate schedule. Bonneville then selects the day with the greatest number of kilowatthours delivered to the purchaser and converts this amount to an equivalent hourly duration, referred to as "demand duration" in the rate schedule.

5. *Wholesale Emergency Capacity CE–1:* The CE–1 rate covers emergency capacity provided to utilities on a weekly basis when available and the return of energy associated with the delivery of this capacity. Bonneville will provide short-term capacity sales only when an emergency condition exists as defined by Bonneville's General Contract Provisions and when Bonneville has the capacity available. To derive the rate, CF–1 contract year rate per kilowatt is divided by the number of weeks in a year and the resultant cost is increased by 15 percent to cover additional administrative and general costs. This results in a rate of $0.71 per kilowattweek for deliveries in the Pacific Northwest. Because costs associated with deliveries over the Pacific Northwest-Pacific Southwest Intertie are not allocated to this service category in the COSA, such deliveries are subject to an additional charge of $0.20 per kilowattweek. This is derived by dividing the intertie costs allocated in the COSA to CF–1 seasonal capacity by the billing determinant for CF–1 seasonal capacity.

6. *New Resource Rate NR–1:* This schedule is available or the purchase of firm power for resale or for direct consumption by purchasers other than DSI customers. It is available for sale to the IOU's to serve their previous year's deficit plus any load growth for the current year and new large single loads of a public body or cooperative. Bonneville anticipates that for FY 1982, less than 5 percent of IOU's resource requirements will be met with the rate and that no public body or cooperative will purchase under the rate schedule.

Section 7(f) of the Act requires the establishment of the rate. It is based only on the costs of the "new resource" pool. Federal Base System resources and exchange resources are serving the loads provided under Sections 7(b) and 7(c) of the Act, and are therefore not available to serve NR–1 loads.

Schedule NR–1 has been time differentiated in the same manner as the Priority Firm rate. The demand charge is also set equal to the demand charge for the PF–1 rate schedule. This adjustment represents a reduction in the demand charge in costs classified to capacity and allocated to the rate. The energy rate was increased to compensate for the reduction in the demand charge.

7. *Wholesale Nonfirm Energy Rate NF–1:* Bonneville's proposed nonfirm energy rate represents a departure from the 1979 share-the-savings rate design. The share-the-savings concept is a

pricing mechanism which attempts to reconcile the difference between the cost of energy to the seller and the value of energy to the purchaser by establishing a price between the two. The proposed NF–1 nonfirm energy rate is designed to reflect the costs of resources used to produce nonfirm energy. Therefore, operational considerations are the basis of this rate design. Bonneville determines the availability of energy to meet firm loads on the basis of critical water conditions. To protect the capability of the FCRPSs to meet firm load obligations in any given operating year, Bonneville operates thermal resources and may make relatively expensive power purchases during the fall and early winter of the year. Subsequently, if snowpack and streamflows prove to be greater than anticipated in late winter and spring, more energy can be produced than is necessary to meet firm loads and nonfirm energy becomes available. Thus, the proposed nonfirm energy rate is based on the costs of power from hydroelectric facilities, from power purchases and from other resources all of which aid in maintaining the capability of Bonneville to meet firm load obligations under critical water but would be in excess or requirements with the occurence of greater streamflows.

Under the current share-the-savings rate, the rate for direct thermal displacement sales is based upon 50 percent of the purchaser's decremental cost, and the rate for an indirect thermal displacement sale is 33 percent of the purchaser's sales price to a utility outside the Pacific Northwest. The diurnally differentiated floor rates are 4.5 and 6.5 mills per kilowatt hour while the ceiling rate is 20 mills per kilowatt hour. In contrast, the rate charged for sales of nonfirm energy under the proposed nonfirm energy rate schedule is based upon: (1) The diurnally differentiated cost of hydroelectric power, (2) the cost of a power purchase, (3) the cost of other resources which have been operated, or (4) a weighted average based on costs from the preceding categories. As any given power purchase or resource is used to derive a rate for a sale of nonfirm energy, that purchase or resource will no longer be used to determine the rate for subsequent sales. A charge of 2.0 mills per kilowatt hour, the average cost of transmission, shall be added to the charge. The floor rates, which are equal to the diurnally differentiated cost of hydroelectric power plus the 2.0 mills per kilowatt hour transmission charge, are 5.0 mills per kilowatt hour for offpeak hours and 6.5 mills per kilowatt hour for peak hours. The ceiling rate is equivalent to the most expensive power purchase or resource which had been operated.

8. *Reserve Power Rate RP–1:* This schedule is available for the purchase of: (a) Firm power to meet a purchaser's unanticipated load growth as provided in a purchaser's power sales contract; (b) power for which Bonneville determines no other rate schedule is applicable; or power to serve a purchaser's firm power loads in circumstances where Bonneville does not have a power sales contract in force with such a purchaser, and Bonneville determines that the rate should be applicable.

The major issue associated with the rate schedule is that the rate is based directly on the results of the long run incremental cost analysis and the time differentiated pricing analysis of long run incremental costs.

9. *Firm Energy Rate FE–1:* Schedule FE–1 is available for contract purchase of firm energy, in the amounts and during the periods specified in the contracts. The level of the rate is equivalent to the average cost of power under the PF–1 rate at 100 percent load factor.

10. *Other Rate Issues:*

a. *Adjustment for Fixed Contract Revenue Deficiencies.* Rates for some transactions are not subject to change because of contractual obligations. The cost-of-service analysis for fiscal year 1982 indicates that, after excess revenues for the nonfirm rate schedules have have been allocated, a revenue deficiency of approximately $63 million would result if this amount were not recovered from other rates. Consequently, all power rate schedules based on FBS resources have been adjusted upward to recover the revenue deficiency associated with these fixed contracts.

b. *Deferred Amortization Payments.* Historical results and future projections of interest and amortization costs for FCRPS are identified in the repayment study and are properly considered when determining revenue level for all classes of service. The initial rate proposal is based on cost estimates and assumptions used in the repayment study and COSA. If any of the estimated projections of loads, costs, or streamflow conditions are not accurate, Bonneville may experience revenue surpluses or shortages. Small temporary revenue shortages can be dealt with by deferring interest and amortization payments on appropriated funds and can be repaid in years with surplus revenue. Sound business principles dictate that this practice can be used only as a temporary means of satisfying cash shortages. Bonneville has not met its planned amortization since 1975. For example, the repayment study supporting Bonneville's current wholesale power rates showed that Bonneville would have approximately $118 million available in FY 1980 to apply to amortization of FCRPS plant investment. However, due to higher than projected costs and reduced revenues, there were no funds for amortization at the end of FY 1980. In addition to not having funds available for amortization payments, Bonneville also had to defer payment of $13.8 million of interest expense to the Treasury.

Bonneville experienced a similar result for FY 1979 when projected revenues available for amortization and interest expense did not materialize. This resulted in Bonneville making no amoritzation payment and deferring $98.6 million of interest payments to the Treasury. As a result of the cash shortage for the past two fiscal years, the total deficit owed the Treasury on September 30, 1980, has increased to $112.4 million. For FY 1981, an additional cash deficit of $44.6 million is anticipated. This will bring the accumulated deficit of unpaid annual costs to a projected $151 million by the close of FY 1981.

Since any accrued deficiency in those payments must ultimately be repaid in order to satisfy Bonneville's statutory obligations, Bonneville is considering options both to cover the accumulated deficit and to avoid the continued nonpayment of forecasted amoritization payments. These options may cause Bonneville's revenue requirement to increase beyond the level identified in the current proposal. Bonneville anticipates that this item will be considered in the preparation of cost data and development of policy for the final repayment studies supporting the final wholesale power rate proposal.

Bonneville is soliciting comments from the public pertaining to the treatment of accumulated deficit and planned amortization requirements. Analysis of this problem is continuing in order to identify the optimal repayment method, but no recommendation has yet been made by Bonneville staff.

c. *Adjustment for Streamflow Conditions.* Although planning criteria for firm power requirements are made on the basis of critical water conditions, actual rates are established on the basis of average water conditions. The initial firm power rates have been set considering an anticipated purchase power expense in FY 82 of $134 million. Projections of the anticipated purchase power requirements cannot be made

with reasonable accuracy until the winter snowpack is measured and analyzed, a process usually accomplished in mid-winter. Therefore, an adjustment to firm power rates mady be necessary in the period January 1982 to June 1982 if streamflows do not meet median levels. The ability to apply surcharges for additional purchases of power has been included in each rate schedule that provides for firm energy loads.

d. *Conservation Costs.* Bonneville is directed to adjust its rates as needed in order to achieve model conservation measures as specified by the Regional Power Act. Power rates are also a potentially signficant tool for encouraging efficient use of energy and thereby supporting Bonneville's legislative mandates of providing low cost power and encouraging widespread use of electricity.

The Bonneville staff has completed a preliminary study of several approaches to rate design which may be effective in encouraging energy efficiency. These approaches include: (1) Using long-urn incremental cost and time-differentiated cost information, (2) employing tiered or inverted rates, (3) reflecting variation in price elasticity in rates, (4) offering billing credits for conservation or the development of renewable resources, and (5) encouraging the use of rate design at the retail level to promote efficient use.

Bonneville's proposed rates reflect the use of both long run incremental cost and time-differentiated pricing in an effort to encourage efficient consumption of resources. The rates do not reflect tiered prices or the application of the inverse elasticity rule because of the lack of conclusive evidence concerning the effectiveness or availability of information necessary for valid implementation of these approaches. The proposed rates are designed to recover $15 million to provide billing credits to customers implementing conservation.

(1) *Long-Run Incremental Cost/Time-Differentiated Pricing:* According to economic theory, an optimum distribution of society's resources can be achieved by pricing all goods and services at their marginal cost. For electricity, marginal cost has traditionally been operationally defined as long-run incremental cost. Theoretically, Bonneville could encourage optimum use of electricity by instituting long run incremental cost pricing.

Whereas LRIC information has been used to develop rates intended to encourage a more efficient distribution of use of capacity and energy, time-of-day and seasonal differentiation analyses have been used to develop rates which reflect differences in the costs of providing capacity and energy by season and the costs of providing capacity by time of day. Theoretically, the incorporation of such time-differentiation in rates would again encourage an increase in the efficiency of resource use by discouraging use during peak periods relative to offpeak periods.

LRIC could also be employed by Bonneville as a standard for judging the cost effectiveness of future resource development. In many cases, the employment of such a standard and the granting of a billing credit based on long-run incremental cost would encourage Bonneville's customers to develop resources which would be cost effective for the region and which might otherwise remain undeveloped.

(2) *Tiered Rates:* The primary rationale for employing a tiered rate to encourage conservation is that customers will respond to their incremental as well as their average cost for power. Under an inverted tiered rate, the incremental cost of power would exceed the customer's average cost. To the extent that the customer responds to incremental as well as average cost, consumption would be expected to be lower under an inverted tiered rate than under a flat rate (where incremental and average costs are equal). There is some question among economists regarding the response of customers to the incremental rate. Many would maintain that the average rate, rather than the incremental rate, determines customer demand for electricity.

(3) *Inverse Elasticity Rule:* Under the inverse elasticity rule, those customers which are most sensitive to price are charged rates closer to marginal cost than are customers with lower price sensitivities. Theoretically, this pricing approach would effectively reduce consumption relative to a uniform pricing approach. Although rates reflecting the application of the inverse elasticity rule have a sound theoretical basis, their effective implementation requires accurate information regarding customer price elasticities. The validity and reliability of customer elasticity estimates currently available to Bonneville is questionable. Substantial improvement of these data would be prerequisite to the employment of this approach in future rate proposals.

(4) *Billing Credits:* Under section 6(h) of the Act, billing credits are to be employed by Bonneville to encourage customers to implement cost effective conservation programs and resources. The availability of low-cost power to Bonneville's preference customers destroys the cost effectiveness of many conservation and resource projects which, if evaluated against Bonneville's incremental cost for power would be considered cost effective. Therefore, with the granting of billing credits, additional conservation and resource development will become cost effective because Bonneville will compare the cost of conservation and resources to its incremental costs.

(5) *Retail Rate Design:* In addition to employing rate design at the wholesale level to encourage conservation, Bonneville may be able to work with its preference customers in an effort to implement rate designs at the retail level which may encourge conservation. A preliminary effort has been made to identify a variety of retail rate design features which may hve a conservation potential. One of these features, inverted rates, has been explored in some detail. Those utilities employing inverted rates in the Northwest have been identified and a literature survey of studies of the effectiveness of inverted retail rates in encouraging conservation has been completed.

(e) *Rate Increase Impacts on Customers:* The impact of the proposed wholesale power rates varies with each customer and among customer classes. The range of effects is due to several factors including load factor differences combined with changes in rate design. and the allocation of cost from the resource pools established in accordance with the Act.

The effect of the increases on Bonneville's publicly owned and Federal agency customers, and industrial customers is of particular interest since these customer groups existed prior to the passage of the Act. Bonneville's analysis of impacts indicates that the effect of the Act is minimal on Bonneville's publicly owned and Federal agency customers. The range of increases for these customers is 50 percent to 59 percent. The average proposed rate increase is 53 percent.

The impact of the proposed industrial firm power rate is more difficult to quantify because the level of the rate after October 1, 1981, depends on the cost of the exchange resources as defined in section 5(c) of the Act. The following is a list of the effects of the proposed industrial firm power rate increase assuming three reasonable estimates of values for the average per unit cost of the exchange.

Exchange resource costs (mills/kWh)	DSI average power cost[1] (mills/kWh)	Percent increase
18	16.0	159
23	19.5	216
25	20.6	234

[1] Does not include value of reserves adjustment.

Dated: February 10, 1981.

Earl Gjelde,

Acting Administrator.

[FR Doc. 81-5373 Filed 2-12-81; 11:00 am]

BILLING CODE 6450-01-M

Reader Aids

Federal Register

Vol. 46, No. 31

Tuesday, February 17, 1981

INFORMATION AND ASSISTANCE

PUBLICATIONS

Code of Federal Regulations

CFR Unit	202-523-3419 523-3517
General information, index, and finding aids	523-5227
Incorporation by reference	523-4534
Printing schedules and pricing information	523-3419

Federal Register

Corrections	523-5237
Daily Issue Unit	523-5237
General information, index, and finding aids	523-5227
Public Inspection Desk	633-6930
Scheduling of documents	523-3187

Laws

Indexes	523-5282
Law numbers and dates	523-5282 523-5266
Slip law orders (GPO)	275-3030

Presidential Documents

Executive orders and proclamations	523-5233
Public Papers of the President	523-5235
Weekly Compilation of Presidential Documents	523-5235

Privacy Act Compilation 523-3517

United States Government Manual 523-5230

SERVICES

Agency services	523-3408
Automation	523-3408
Dial-a-Reg	
Chicago, Ill.	312-663-0884
Los Angeles, Calif.	213-688-6694
Washington, D.C.	202-523-5022
Magnetic tapes of FR issues and CFR volumes (GPO)	275-2867
Public briefings: "The Federal Register—What It Is and How To Use It"	523-5235
Public Inspection Desk	633-6930
Regulations Writing Seminar	523-5240
Special Projects	523-4534
Subscription orders and problems (GPO)	783-3238
TTY for the deaf	523-5239

FEDERAL REGISTER PAGES AND DATES, FEBRUARY

10135-10450.....2
10451-10704.....3
10705-10894.....4
10895-11224.....5
11225-11500.....6
11501-11654.....9
11655-11800.....10
11801-11942.....11
11943-12190.....12
12191-12468.....13
12469-12690.....17

CFR PARTS AFFECTED DURING FEBRUARY

At the end of each month, the Office of the Federal Register publishes separately a list of CFR Sections Affected (LSA), which lists parts and sections affected by documents published since the revision date of each title.

3 CFR

Administrative Orders:
Presidential Determinations:
No. 81-2 of January 16, 1981.....11225
Memorandums:
January 29, 1981.....11227
Executive Orders:
12092 (Revoked by EO 12288).....10135
12278 (correction).....10895
12279 (correction).....10897
12288.....10135
Proclamations:
4818.....11801

4 CFR

20.....10451

5 CFR

Ch. XIV.....11655
213.....11229
752.....12191
2424.....12191

6 CFR

705.....11229
706.....11229
707.....11229

7 CFR

Ch. I.....11501
Ch. II.....11501
Ch. IX.....11501
Ch. XVIII.....11501
Ch. XXVIII.....11501
29.....10451
724.....11229
726.....11235
905.....10899, 11655, 11656
907.....10900, 11943
910.....11237, 12191
1421.....10137, 10900, 11803
Proposed Rules:
985.....12000
1701.....10498, 11287
1747.....10746
1941.....11552
1962.....11666
2851.....10498

8 CFR

211.....10901
214.....10901, 11501

9 CFR

Proposed Rules:
318.....10500
381.....10500

10 CFR

2.....12192
30.....11666
34.....11804
40.....11237, 11666
50.....11666
70.....11666, 12193
72.....11666
73.....12193
205.....11237
211.....11943
212.....11804
456.....11943
712.....11943
1020.....11943
Proposed Rules:
Ch. I.....10747
50.....10501, 11288
211.....11291

12 CFR

203.....11780
206.....11237
217.....10452
544.....10705
545.....10705
546.....10705
552.....11502
571.....10705
Proposed Rules:
Ch. II.....10747

13 CFR

118.....10455
119.....10455
Proposed Rules:
120.....12500
124.....10501

14 CFR

39.....10140, 11503-11506, 11944-11947, 12469-12474
43.....10705, 10902, 10903
71.....10903, 10904, 11507-11508, 11948-11951, 12475-12477
75.....11952
91.....10705, 10902, 10903
97.....11509
121.....10705, 10902, 10903
123.....10705, 10902, 10903
125.....10705, 10902, 10903
135.....10705, 10902, 10903
145.....10705, 10902, 10903
207.....10455
208.....10457
212.....10457
214.....10457
298.....12477
324.....11806
385.....11807
399.....11808, 11809
Proposed Rules:
39.....10163, 11552

67 12001
71 ..... 10164, 11553–11555, 12001–12004, 12500, 12501
207 10164
208 10164
212 10164
214 10164
241 11827
252 11827
298 11555

15 CFR

19 11657
376 11809
379 11809
938 10141

16 CFR

13 12479
1212 10458
1500 11511

Proposed Rules:

Ch. I 10502, 12208
13 10921
423 10165
436 ..... 11830, 12005
457 10747
1306 11188

17 CFR

200 ..... 10904, 11810
210 12480
211 11513
229 ..... 11952, 12480
230 ..... 12195, 12480
239 11952
240 12480
241 ..... 11544, 11954
249 12480
250 12480
260 12480

Proposed Rules:

1 11668
229 12011
240 12011

18 CFR

4 ..... 10458, 11811
154 12198
270 12198
271 ..... 10141, 10460, 11811, 11812
273 12198
282 ..... 10148, 11812
292 11251

Proposed Rules:

2 10165
4 10165
5 10165
16 10165
35 12208
131 10165
271 11839–11842

19 CFR

355 10905

20 CFR

655 ..... 11253, 12205
676 ..... 11253, 12205
677 ..... 11253, 12205
678 ..... 11253, 12205
679 ..... 11253, 12205

21 CFR

14 12205
178 10461
510 ..... 10462, 10464
520 10463
522 10463
558 10464
1030 10465

Proposed Rules:

207 12211
210 12211
225 12211
226 12211
351 11292
501 12211
510 12211
514 12211
558 12211
610 11672
814 12502
868 12212

22 CFR

22 11968
41 10906
901 11180
902 11181
903 11181
904 11182
905 11183
906 11184
907 11184
908 11184
909 11184

23 CFR

140 ..... 10706, 10906
450 ..... 10706, 10906
630 ..... 10706, 10906
655 ..... 10706, 10906
656 ..... 10706, 10906
765 ..... 10706, 10906

Proposed Rules:

635 10177
1221 10922

24 CFR

42 11550
201 11550
215 11550
241 11550
300 11550
510 11550
885 11550
3282 11550
3500 11550
3610 11550

Proposed Rules:

868 10922

25 CFR

52 10707
53 10707

26 CFR

1 ..... 11255, 11971
5 11255
7 11255
10 11255
15A 10708
26a 10907
31 10148
53 11254
55 11255
150 11284

Proposed Rules:

26a 12502
1 ..... 10510, 10749
48 10923
51 11292

27 CFR

4 12493
9 12493
19 12205
211 12494
212 12494
240 12205
245 12205
250 12205
270 12205
275 12205

Proposed Rules:

181 10512

29 CFR

1 ..... 10465, 11253, 12205
2 10465
4 ..... 11284, 11971, 12206
5 ..... 10466, 11253, 12205
6 ..... 11253, 12205
207 12206
208 12206
209 12206
541 ..... 11972, 12206
1613 11284
1903 ..... 11253, 12205
1910 ..... 11253, 12205
1952 ..... 11253, 12205
1955 ..... 11253, 12205
1990 ..... 11253, 11286, 12205
2520 ..... 10465, 11253, 12205
2550 ..... 10465, 11253, 12205
2560 ..... 11253, 12205
2608 10720
2615 10720
2652 11658

Proposed Rules:

Ch. XIV 10177
29 12213
505 11672
1910 ..... 12020, 12213
2510 ..... 11292, 12214
2520 10512

30 CFR

71 10465
90 10465
211 10707
221 10707
231 10707
250 10707
270 10707
700 10707
716 10707
785 10707
948 10707
950 10707

Proposed Rules:

715 11672
731 11843
732 11843
816 11672
817 11672

31 CFR

51 10908

32 CFR

59 10908
201 12494
826 10708
2200 11659

Proposed Rules:

504 11672

33 CFR

117 ..... 10706, 10906
157 ..... 10706, 10906
161 ..... 10706, 10906
162 ..... 10706, 10906
209 11659

Proposed Rules:

155 11556
207 10923

34 CFR

75 ..... 10153, 10721, 12495
76 10721
78 12495
104 12495
200 12495
201 12495
208 10153
211 12495
215 12495
220 10153
223 12495
230 12495
231 12495
300 12495
305 12495
307 12495
309 12495
315 12495
318 12495
322 12495
324 12495
332 12495
338 12495
361 12495
362 12495
365 12495
366 12495
369 12495
370 12495
371 12495
372 12495
373 12495
374 12495
375 12495
378 12495
379 12495
385 12495
386 12495
387 12495
388 12495
389 12495
390 12495
395 12495
408 12495
525 12495
526 12495
527 12495
605 11661
606 11661
624 12495
642 11661
643 ..... 11661, 12495
644 ..... 11661, 12495
645 ..... 11661, 12495
646 ..... 11661, 12495

649.....12495
655.....12495
656.....12495
658.....12495
660.....12495
667.....12495
668.....11661, 12495
674.....11661, 12495
675.....11661, 12495
676.....11661, 12495
682.....11661, 12495
683.....11661, 12495
690.....11661, 12495
692.....11661
726.....12495
735.....12495
740.....12495
753.....12495
757.....12495
776.....10721
778.....10721

Proposed Rules:

100.....10516
605.....11678
606.....11678
642.....11678
643.....11678
644.....11678
645.....11678
646.....11678
668.....11678
674.....11678
675.....11678
676.....11678
682.....11678
683.....11678
690.....11678
692.....11678

36 CFR

7.....12496
219.....11501
223.....10497, 11501

Proposed Rules:

7.....11556

37 CFR

2.....11548
307.....10466

38 CFR

3.....11661

39 CFR

111.....10154, 10721, 11548

Proposed Rules:

10.....11296
111.....11301
776.....10513

40 CFR

6.....11972
7.....11662
51.....10910
52.....10910, 11972
56.....10911, 11972
81.....11813, 12496
122.....12414
123.....10487
162.....11972
230.....11972
262.....12207
263.....12207
264.....10911
265.....10911
267.....12414
401.....10723
403.....11972
413.....11972
429.....11972
707.....10912

Proposed Rules:

Ch. I.....10177
52.....10750, 11309–11321, 11678, 11843, 12020, 12522
58.....12022
60.....10752, 11490, 11557, 12023
61.....12188
81.....12023
122.....11126, 11680
180.....11680, 11681
230.....11323
260.....11126, 11680
264.....11126, 11680
410.....11322
610.....11322

41 CFR

Ch. 18 (Parts 3, 4, 5).....10489
Ch. 18 (Parts 3, 20, Appendix E).....10495
7–4.....10912
7–7.....10912
60–1.....11253, 12205

Proposed Rules:

1–4.....10924
9.....12646
29–15.....11323
101–43.....11845
101–47.....11845

43 CFR

9.....10707
2090.....10707
2091.....10707
2200.....10707
2210.....10707
2220.....10707
2250.....10707
2260.....10707
2270.....10707
2300.....10707
2310.....10707
2320.....10707
2340.....10707
2350.....10707
2920.....10707
4100.....10497, 12496

Proposed Rules:

3100.....11557
3500.....11557

Public Land Orders:

1109 (Revoked by PLO 5849).....11973
1258 (Revoked by PLO 5848).....11973
3869 (Revoked in part by PLO 5855).....11973
5797.....10707
5798.....10707
5799.....10707
5802.....10707
5803.....10155
5804.....10707, 11973
5805.....10707
5806.....10707
5809.....10707
5811.....12207
5812.....10707
5814.....10707
5817.....10707
5818.....10707, 12207
5819.....10707
5820.....11973
5821.....10707
5824.....10707
5825.....10707, 12497
5826.....10707
5827.....10707
5828.....10707, 12497
5829.....12497
5830.....10707
5831.....10707
5832.....10707
5833.....10707, 12497
5834.....10707
5835.....12497
5836.....10707
5837.....10707
5838.....10707
5839.....10707, 12497
5840.....10707
5841.....10707
5842.....10707
5844.....10707
5845.....10707, 12207
5846.....10707
5848.....10707, 11973
5849.....10707, 11973
5850.....10707
5851.....10707
5852.....10707, 11973
5853.....10707
5854.....10707
5855.....10707, 11973

44 CFR

64.....11813, 11816, 11818, 11819

Proposed Rules:

67.....10753–10763, 11682–11688

45 CFR

1012.....11973, 12498
1067.....12499

Proposed Rules:

1070.....12522
1152.....11557

46 CFR

Proposed Rules:

12.....11565
13.....11565
30.....11565
31.....11565
35.....11565
50.....12524
54.....12524
56.....12524
58.....12524
61.....12524
70.....11565
90.....11565
98.....11565
105.....11565
151.....11565
153.....11565
157.....11565
381.....10515
520.....12524
524.....10178
549.....10767

47 CFR

2.....11974
17.....10915
73.....10724–10737, 10916, 11549, 11825, 11983
81.....10155
90.....11974
97.....10915

Proposed Rules:

Ch. I.....10924, 11846, 12024, 12032
2.....10768
22.....10768
73.....10177, 10772–10784, 10963–10968, 11846
76.....12525
90.....11847
94.....10768

48 CFR

Proposed Rules:

7.....11324

49 CFR

1.....10919
173.....10706, 10906
179.....10706, 10906
192.....10157, 10706, 10906
195.....10157, 10706, 10906
460.....10706, 10906
613.....10706, 10906
635.....10706, 10906
639.....10706, 10906
640.....10706, 10906
642.....10706, 10906
1033.....10497, 10740–10743
1048.....11286
1109.....10162
1201.....10919
1206.....10919
1207.....10919
1248.....10745
1254.....11662
1331.....10920

Proposed Rules:

512.....10969
571.....10179, 10428, 10969, 12033
575.....10429
1039.....12526
1043.....11566
1044.....10180
1084.....11566
1090.....12526
1109.....10181, 10182
1300.....12526

50 CFR

17.....10707, 11665, 11999
285.....12207

Proposed Rules:

17.....11567, 12214
23.....12215
216.....10785
611.....10182
639.....10515
643.....10182
661.....10182

AGENCY PUBLICATION ON ASSIGNED DAYS OF THE WEEK

The following agencies have agreed to publish all documents on two assigned days of the week (Monday/Thursday or Tuesday/Friday). This is a voluntary program. (See OFR NOTICE 41 FR 32914, August 6, 1976.)

Monday	Tuesday	Wednesday	Thursday	Friday
DOT/SECRETARY	USDA/ASCS		DOT/SECRETARY	USDA/ASCS
DOT/COAST GUARD	USDA/FNS		DOT/COAST GUARD	USDA/FNS
DOT/FAA	USDA/FSQS		DOT/FAA	USDA/FSQS
DOT/FHWA	USDA/REA		DOT/FHWA	USDA/REA
DOT/FRA	MSPB/OPM		DOT/FRA	MSPB/OPM
DOT/NHTSA	LABOR		DOT/NHTSA	LABOR
DOT/RSPA	HHS/FDA		DOT/RSPA	HHS/FDA
DOT/SLSDC			DOT/SLSDC	
DOT/UMTA			DOT/UMTA	
CSA			CSA	

Documents normally scheduled for publication on a day that will be a Federal holiday will be published the next work day following the holiday.
Comments on this program are still invited.
Comments should be submitted to the Day-of-the-Week Program Coordinator, Office of the Federal Register, National Archives and Records Service, General Services Administration, Washington, D.C. 20408

NOTE: As of September 2, 1980, documents from the Animal and Plant Health Inspection Service, Department of Agriculture, will no longer be assigned to the Tuesday/Friday publication schedule.

List of Public Laws

Note: No public bills which have become law were received by the Office of the Federal Register for inclusion in today's **List of Public Laws.**

[Last Listing February 13, 1981]

THE FEDERAL REGISTER: WHAT IT IS AND HOW TO USE IT

FOR: Any person who uses the Federal Register and Code of Federal Regulations.

WHO: The Office of the Federal Register.

WHAT: Free public briefings (approximately 2½ hours) to present:

1. The regulatory process, with a focus on the Federal Register system and the public's role in the development of regulations.
2. The relationship between Federal Register and the Code of Federal Regulations.
3. The important elements of typical Federal Register documents.
4. An introduction to the finding aids of the FR/CFR system.

WHY: To provide the public with access to information necessary to research Federal agency regulations which directly affect them, as part of the General Services Administration's efforts to encourage public participation in Government actions. There will be no discussion of specific agency regulations.

WHEN: March 13 and 27, April 10 and 24; at 9 a.m. (identical sessions).

WHERE: Office of the Federal Register, Room 9409, 1100 L Street NW., Washington, D.C.

RESERVATIONS: Call King Banks, Workshop Coordinator, 202–523–5235.

The list of agency billing codes assigned by the Government Printing Office follows:

Department	*Billing Code*
National Mediation Board	7550-01
National Railroad Passenger Corporation	0000-00
National Science Foundation	7555-01
National Security Agency/Central Security Service	3810-70
National Transportation Safety Board	4910-58
Neighborhood Reinvestment Corporation	
New England River Basins Commission	8410-01
Nuclear Regulatory Commission	7590-01
Nuclear Safety Oversight Commission	6820-01
Occupational Safety and Health Review Commission	7600-01
Oceans and Atmosphere National Advisory Committee	3510-12
Ohio River Basin Commission	8410-01
Overseas Private Investment Corporation	3210-01
Panama Canal Commission	3640-01
Peace and Conflict Resolution, Commission on Proposals for National Academy	4000-01
Pennsylvania Avenue Development Corporation	7630-01
Pension Benefit Guaranty Corporation	7708-01
Pension Policy, President's Commission	6820-99
Personnel Management Office	6325-01
Postal Rate Commission	7715-01
Postal Service	7710-12
Radiation Policy Council	6560-01
Railroad Retirement Board	7905-01
Railway Association, U.S.	8240-01
Regulatory Council	3194-01
Science and Technology Policy Office	3170-01
Securities and Exchange Commission	8010-01
Select Commission on Immigration and Refugee Policy	6820-AR
Selective Service System	8015-01
Sinai Support Mission	4710-10
Small Business Administration	8025-01
Small Business Conference Commission	8025-01
Smithsonian Institution	8030-03
State Department:	
Office of the Secretary	4710-01, 4710-05, 4710-06, 4710-07, 4710-08, 4710-09, 4710-10, 4710-11, 4710-12, 4710-15, 4710-16, 4710-17, 4710-18, 4710-19, 4710-20
Susquehanna River Basin Commission	7040-01
Synthetic Fuels Corporation	6450-01
Technology Assessment Office	1630-01
Tennessee Valley Authority	8120-01
Thrift Institutions Study, Interagency Task Force	4810-27
Trade Representative, Office of U.S	3190-01
Transportation Department:	
Coast Guard	4910-14
Federal Aviation Administration	4910-09, 4910-13
Federal Highway Administration	4910-22
Federal Railroad Administration	4910-06
Materials Transportation Bureau	4910-60
National Highway Traffic Safety Administration	4910-59
Research and Special Programs Administration	4910-62
St. Lawrence Seaway Development Corporation	4910-61
Urban Mass Transportation Administration	4910-57
Treasury Department:	
Alcohol, Tobacco and Firearms Bureau	4810-31
Central Services Office	4810-27
Comptroller of the Currency	4810-33
Customs Service	4810-22
Engraving and Printing Bureau	4810-34
Federal Law Enforcement Training Center	4810-32
Fiscal Service	4810-35, 4810-40
Government Financial Operations Bureau	4810-35
Internal Revenue Service	4830-01
Mint Bureau	4810-37
Office of the Secretary	4810-25
Public Debt Bureau	4810-40
Revenue Sharing	4810-28
Savings Bonds Division	4810-41
Secret Service	4810-42
Uniformed Services University of the Health Sciences	3810-70
Upper Mississippi River Basin Commission	8410-02
U.S. Courts	2210-01
Veterans Administration	8320-01
Vice President	3196-01
Wage and Price Stability Council	3175-01
Water Resources Council	8410-01
White House Fellowships, Presidents' Commission	6325-01
White House Office	3195-01
Women, President's Advisory Committee	4510-23

The list of agency billing codes assigned by the Government Printing Office follows:

Department	*Billing Code*
Environmental Protection Agency—Continued	
Research and Development	6560-35
Science Advisory Board	6560-34
Solid Waste Management	6560-30
Toxic Substances Office	6560-25
Toxics	6560-31
Water Program	6560-29
Environmental Quality Council	3125-01
Equal Employment Opportunity Commission	6570-06
Ethical Problems in Medicine and Biomedical and Behavioral Research, President's Commission for the Study of	6820-AV
Executive, Legislative, and Judicial Salaries Commission	6820-BA
Export-Import Bank of the U.S.	6690-01
Farm Credit Administration	6705-01
Federal Communications Commission	6712-01
Federal Deposit Insurance Corporation	6714-01
Federal Election Commission	6715-01
Federal Emergency Management Agency	6718-01
Disaster Response and Recovery	6718-02
Federal Insurance Administration	6718-03
Fire Administration, U.S.	6718-04
Federal Financial Institutions Examination Council	6722-01
Federal Home Loan Bank Board	6720-01
Federal Home Loan Mortgage Corporation	6720-02
Federal Labor Relations Authority	6727-01
Federal Maritime Commission	6730-01
Federal Mediation and Conciliation Service	6732-01
Federal Mine Safety and Health Review Commission	6820-12
Federal Pay Advisory Committee	6820-43
Federal Prevailing Rate Advisory Committee	6325-01
Federal Register Office	1505-02
Federal Reserve System	6210-01
Federal Service Impasses Panel	6727-01
Federal Trade Commission	6750-01
Fine Arts Commission	6330-01
Foreign Claims Settlement Commission	6770-01
General Accounting Office	1610-01
General Services Administration:	
Administrator's Office	6820-34
Automated Data and Telecommunications Service	6820-25
Data Systems Office	6820-37
Federal Property Resources Service	6820-96
Federal Register Office	1505-02
Federal Supply Service	6820-24
National Archives and Records Service	6820-26
Personnel Office	6820-30
Public Building Service	6820-23
Transportation and Public Utility Service	6820-AM
Government Printing Office	1505-01
Great Lakes Basin Commission	8415-01
Harry S Truman Scholarship Foundation	6115-02
Hazardous Substances Export Policy, Interagency Working Group	3510-25
Health and Human Services Department:	
Alcohol, Drug Abuse, and Mental Health Administration	4110-88
Center for Disease Control	4110-86
National Institute for Occupational Safety and Health	4110-87
Food and Drug Administration	4110-03
Health Care Financing Administration	4110-35
Health Resources Administration	4110-83
Health Services Administration	4110-84
Human Development Services Office	4110-92
National Institutes of Health	4110-08
Office of the Secretary	4110-12
Public Health Service:	
Assistant Secretary for Health	4110-85
Social Security Administration	4110-07
Historic Preservation Advisory Council	4310-10
Holocaust, President's Commission	4310-70
Housing and Urban Development Department	4210-01
Immigration and Refugee Policy Select Commission	6820-AR
Information Security Oversight Office	6820-AF
Inter-American Foundation	7025-01
Interagency Coordinating Council	6450-01
Interagency Regulatory Liaison Group	6560-01
Interagency Testing Committee	6560-31
Intergovernmental Relations Advisory Commission	6115-01
Interior Department:	
Fish and Wildlife Service	4310-55
Geological Survey	4310-31
Heritage Conservation and Recreation Service	4310-03
Indian Affairs Bureau	4310-02
Land Management Bureau	4310-84

Department	*Billing Code*
Interior Department—Continued	
Lowell Historic Preservation Commission	4310-KD
Micronesian Status Negotiation Office	4310-56
Mines Bureau	4310-53
National Park Service	4310-70
Navajo and Hopi Indian Relocation Commission	4310-HB
Office of the Secretary	4310-10
Reclamation Bureau	4310-09
Solicitor's Office	4310-17
Surface Mining Reclamation and Enforcement Office	4310-05
Territorial Affairs Office	4310-93
Water and Power Resources Service	4310-09
Water Research and Technology Office	4310-49
Young Adult Conservation Corps	4310-HJ
International Boundary and Water Commission, U.S. and Mexico	4710-03
International Broadcasting Board	6155-01
International Communication Agency	8230-01
International Convention Advisory Commission	4310-68
International Development Cooperation Agency	4710-02
Agency for International Development	4710-02
International Joint Commission, U.S. and Canada	4710-14
International Labor Organization, President's Committee	4510-28
International Trade Commission	7020-02
Interstate Commerce Commission	7035-01
Japan-U.S. Economic Relations Group	6820-AT
Japan-U.S. Friendship Commission	6820-95
Joint Board for the Enrollment of Actuaries	4810-25
Justice Department	4410-01
Drug Enforcement Administration	4410-09
Federal Bureau of Investigation	4410-02
Immigration and Naturalization Service	4410-10
Law Enforcement Assistance Administration	4410-18
Justice Assistance, Research, and Statistics Office	4410-18
Justice Statistics Bureau	4410-18
National Institute of Justice	4410-18
National Institute of Corrections	4410-36
Prisons Bureau	4410-05
Labor Department:	
Employment and Training Administration	4510-30
Employment Standards Administration	4510-27
Wage and Hour Division	4510-27
Executive Secretariat	4510-64
Federal Contract Compliance Programs Office	4510-27
International Labor Affairs Bureau	4510-28
Labor Management Relations Office	4510-29
Labor Management Standards Enforcement Office	4510-23
Labor-Management Services Administration	4510-29
Labor Statistics Bureau	4510-24
Management Services Administration	4510-29
Mine Safety and Health Administration	4510-43
Occupational Safety and Health Administration	4510-26
Office of the Secretary	4510-23
Administrative Law Judges	4510-20
Audit and Investigations	4510-21
Information Office	4510-22
Pension and Welfare Benefit Programs	4510-29
Legal Services Corporation	6820-35
Libraries and Information Science, National Commission	7527-01
Library of Congress	1410-01
Cable TV	1410-06
Copyright Office	1410-03
Jukebox	1410-07
Management and Budget Office	3110-01
Federal Procurement Policy Office	3110-01
Management Improvement, Presidents' Council	6325-01
Marine Mammal Commission	6820-31
Merit Systems Protection Board	7400-01, 7400-02
Metric Board, U.S.	6820-94
Metric Policy Interagency Committee	6820-94
Mississippi River Commission	3710-GX
National Aeronautics and Space Administration	7510-01
National Agenda for the Eighties	3110-01
National Alcohol Fuels Commission	6820-AN
National Capital Planning Commission	7520-01
National Commission on Social Security	6820-AC
National Commission on Unemployment Compensation	4510-27
National Communications System	3610-05
National Consumer Cooperative Bank	4810-25
National Credit Union Administration	7535-01
National Endowment for the Arts	7537-01
National Endowment for the Humanities	7536-01
National Labor Relations Board	7545-01

BILLING PROCEDURES FOR AGENCIES

As part of the billing procedures announced in the FEDERAL REGISTER of August 24, 1977, and to insure that each agency is correctly billed for only its own documents, the Office of the Federal Register requests agencies to insert the proper billing code on all of their documents. The six-digit billing code should be typed or handwritten in ink at the top of the first page on all three copies of documents submitted to the Office of the Federal Register for publication, as follows:

BILLING CODE: 0000-00

The list of agency billing codes assigned by the Government Printing Office follows:

Department	*Billing Code*
ACTION	6050-01
Actuaries, Joint Board for Enrollment	4810-25
Administration Office, Executive Office of the President	3115-01
Administrative Committee of the Federal Register	1505-02
Administrative Conference of the United States	6110-01
Aging, Federal Council	4110-92
Agriculture Department:	
Agricultural Marketing Service	3410-02
Agricultural Research Service	3410-03
Agricultural Stabilization and Conservation Service	3410-05
Animal and Plant Health Inspection Service	3410-34
Budget, Planning, and Evaluation Office	3410-90
Commodity Credit Corporation	3410-05
Contract Appeals Board	3410-25
Economics, Statistics, and Cooperatives Service	3410-18
Energy Office	3410-73
Environmental Quality Office	3410-HP
Equal Opportunity Office	3410-95
Farmers Home Administration	3410-07
Federal Crop Insurance Corporation	3410-08
Federal Grain Inspection Service	3410-EN
Food and Nutrition Service	3410-30
Food Safety and Quality Service	3410-DM
Foreign Agricultural Service	3410-10
Forest Service	3410-11
General Sales Manager Office	3410-21
Inspector General's Office	3410-23
Management Staff	3410-FW
Office of the Secretary	3410-01
Operations Office	3410-98
Personnel Office	3410-96
Rural Electrification Administration	3410-15
Safety and Health Management Office	3410-FV
Science and Education Administration	3410-03
Soil Conservation Service	3410-16
Transportation Office	3410-GS
Air Quality National Commission	6820-98
Alaska Natural Gas Transportation System, Office of the Federal Inspector for	6820-AW
Arms Control and Disarmament Agency	6820-32
American Battle Monuments Commission	6120-01
Architectural Transportation Barriers Compliance Board	4110-12
Blind and Other Severely Handicapped, Committee for Purchase from	6820-33
Central Intelligence Agency	6310-02
Chrysler Corporation Loan Guarantee Board	4810-27
Civil Aeronautics Board	6320-01
Civil Rights Commission	6335-01
Commerce Department:	
Census Bureau	3510-07
Economic Analysis Bureau	3510-BG, 3510-06
Economic Development Administration	3510-24
Foreign Trade Zones Board	3510-25
Industrial Economics Bureau	3510-30
International Trade Administration	3510-25
Maritime Administration	3510-15
Minority Business Development Agency	3510-21
National Bureau of Standards	3510-13
National Oceanic and Atmospheric Administration	3510-12
Coastal Zone Management	3510-08
National Marine Fisheries Service	3510-22
National Technical Information Service	3510-04
National Telecommunications and Information Administration	3510-60
Office of the Secretary	3510-BP
3510-BR, 3510-BS, 3510-BT, 3510-BV, 3510-BW, 3510-BX, 3510-BY, 3510-17, 3510-19, 3510-36	
Patent and Trademark Office	3510-16
Science and Technology Office	3510-18
Textile Agreements Implementation Committee	3510-25
Commerce Department—Continued	
Textile Agreements Implementation Committee	3510-25
Travel Service, U.S	3510-11
Commodity Futures Trading Commission	6351-01
Community Services Administration	6315-01
Consumer Product Safety Commission	6355-01
Copyright Royalty Tribunal	1410-01
Defense Department:	
Air Force Department	3910-01
Army Department	3710-08, 3710-92
Engineers Corps:	
Alaska District	3710-NL
Albuquerque District	3710-KK
Baltimore District	3710-41
Buffalo District	3710-GP
Chicago District	3710-HN
Cincinnati District	3710-85
Dallas District	3710-ML
Detroit District	3710-GA
Fort Worth District	3710-FR, 3710-GE
Galveston District	3710-GK
Hawaii District	3710-NN
Huntington District	3710-GM
Jacksonville District	3710-AJ
Kansas City District	3710-KN
Little Rock District	3710-GL
Los Angeles District	3710-KF
Louisville District	3710-JB
Memphis District	3710-KS
Mobile District	3710-CR
Nashville District	3710-GF
New York District	3710-06
Norfolk District	3710-EN
North Central, Chicago District	3710-FT
Philadelphia District	3710-GR
Sacramento District	3710-GH
St. Louis District	3710-GS
St. Paul District	3710-CY
San Francisco District	3710-FS
Savannah District	3710-HP
Seattle District	3710-GB
Tulsa District	3710-39
Vicksburg District	3710-GX 3710-PU
Walla Walla District	3710-GC
Wilmington District	3710-GN
Navy Department	3810-70
JAG	3810-71
Defense Communications Agency	3610-05
Defense Intelligence Agency	3810-70
Defense Investigative Service	3810-70
Defense Logistics Agency	3620-01
Defense Mapping Agency	3810-70
Defense Nuclear Agency	3810-70
Defense Supply Agency	3810-70
Delaware River Basin Commission	6360-01
Depository Institutions: Deregulation Committee	6210-01
Economic Advisers Council	3120-01
Economic Opportunity, National Advisory Council	6820-42
Education Department	4000-01
Museums Services Institute	4000-02
National Institute of Education	4000-05
Employment Policy, National Commission	4510-30
Endangered Species Committee	4310-10
Energy Department	6450-01
Federal Energy Regulatory Commission	6450-85
Environmental Protection Agency	6560-26
Administrator's Staff	6560-36
Enforcement	6560-33
Environmental Review Office	6560-37
Noise Program	6560-27
Pesticides	6560-32
Radiation	6560-28
Regional Offices	6560-38